ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

JOINT PETITION AND APPLICATION OF DUKE ENERGY INDIANA ENERGY, INC., D/B/A DUKE ENERGY INDIANA, INC., AND SOUTHERN INDIANA GAS AND ELECTRIC COMPANY, D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC., PURSUANT TO INDIANA CODE CHAPTERS 8-1-8.5, 8-1-8.7, 8-1-8.8, AND SECTIONS 8-1-2-6.8, 8-1-2-6.7, 8-1-2-42(a) REQUESTING THAT THE COMMISSION: (1) ISSUE APPLICABLE CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY AND APPLICABLE CERTIFICATES OF CLEAN COAL TECHNOLOGY TO EACH JOINT PETITIONER FOR THE CONSTRUCTION OF AN INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") TO BE USED IN THE PROVISION OF ELECTRIC UTILITY SERVICE TO THE PUBLIC; (2) APPROVE THE ESTIMATED COSTS AND SCHEDULE OF THE IGCC PROJECT; (3) AUTHORIZE EACH JOINT PETITIONER TO RECOVER ITS CONSTRUCTION AND OPERATING COSTS ASSOCIATED WITH THE IGCC PROJECT ON A TIMELY BASIS VIA APPLICABLE RATE ADJUSTMENT MECHANISMS; (4) AUTHORIZE EACH JOINT PETITIONER TO USE ACCELERATED DEPRECIATION FOR THE IGCC PROJECT; (5) APPROVE CERTAIN OTHER FINANCIAL INCENTIVES FOR EACH JOINT PETITIONER ASSOCIATED WITH THE IGCC PROJECT; (6) GRANT EACH JOINT PETITIONER THE AUTHORITY TO DEFER ITS PROPERTY TAX EXPENSE, POST-IN-SERVICE CARRYING COSTS, DEPRECIATION COSTS, AND OPERATION AND MAINTENANCE COSTS ASSOCIATED WITH THE IGCC PROJECT ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN EACH JOINT PETITIONER'S RESPECTIVE RETAIL ELECTRIC RATES; (7) AUTHORIZE EACH JOINT PETITIONER TO RECOVER ITS OTHER RELATED COSTS ASSOCIATED WITH THE IGCC PROJECT; AND (8) CONDUCT AN ONGOING REVIEW OF THE CONSTRUCTION OF THE IGCC PROJECT	)	CAUSE NO. 43114
VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. FOR AUTHORITY PURSUANT TO AN ALTERNATIVE REGULATORY PLAN AUTHORIZED UNDER IND. CODE § 8-1-2.5 ET SEQ. AND IND. CODE §§ 8-1-2-6.1, 8-1-8.7, AND 8-1-8.8 TO DEFER AND SUBSEQUENTLY RECOVER ENGINEERING AND PRECONSTRUCTION COSTS ASSOCIATED WITH THE CONTINUED INVESTIGATION AND ANALYSIS OF CONSTRUCTING AN INTEGRATED COAL GASIFICATION COMBINED CYCLE ELECTRIC GENERATING FACILITY	)	CAUSE NO. 43114-S1 APPROVED: NOV 2 0 2007

BY THE COMMISSION:
David E. Ziegner, Commissioner
Gregory D. Server, Commissioner
Scott R. Storms, Chief Administrative Law Judge

On September 7, 2006, Duke Energy Indiana, Inc., ("Duke Energy Indiana" "Petitioner" or "Company") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") in this Cause.[1] In its Petition, Duke Energy Indiana requested: (1) the issuance of applicable certificates of public convenience and necessity and applicable certificates of clean coal technology for the construction of an integrated gasification combined cycle generating facility ("IGCC Project" or the "Edwardsport IGCC Project") pursuant to Ind. Code (IC) 8-1-8.5, 8-1-8.7 and 8-1-8.8; (2) the approval of the estimated costs and schedule of the IGCC Project; (3) the authority to recover its construction and operating costs associated with the IGCC Project on a timely basis via applicable rate adjustment mechanisms; (4) the authority to use accelerated depreciation for the IGCC Project; (5) the approval of certain additional financial incentives associated with the IGCC Project; (6) the authority to defer its property tax expense, post-in-service carrying costs, depreciation costs, and operation and maintenance costs associated with the IGCC Project on an interim basis until the applicable costs are reflected in Petitioner's retail electric rates; (7) the authority to recover other related costs associated with the IGCC Project; and (8) that the Commission conduct an ongoing review of the construction of the IGCC Project.

On January 12, 2007, the Petitioner filed a motion for a subdocket, in which it requested interim cost recovery of costs associated with the study and development of the IGCC Project that were required to be incurred prior to the estimated date of a final order in this Cause. Pursuant to a Prehearing Conference Order issued February 28, 2007, the Commission consolidated the two Causes for filing and hearing purposes. Duke Energy Indiana indicated in its Rebuttal testimony that it had agreed to withdraw its request for interim cost recovery, in return for agreement from the OUCC and Intervenors on an expedited post-hearing briefing schedule.

After the prefiling of testimony by all parties, an Evidentiary Hearing in this proceeding was conducted on June 18–22, 2007, in Suite 220 of the National City Center, 101 W. Washington Street, Indianapolis, Indiana. The parties to this proceeding, other than Duke Energy Indiana, included the Indiana Office of Utility Consumer Counselor ("OUCC"); the Citizens Action Coalition of Indiana, Inc. ("CAC"); Save the Valley, Inc. ("STV"); Valley Watch, Inc. ("Valley Watch"); the Sierra Club, Hoosier Chapter ("Sierra Club"); the Indiana Industrial Group ("IIG"); Nucor Steel, a division of Nucor Corporation ("Nucor"); the Indiana Wildlife Federation ("IWF"); the Clean Air Task Force ("CATF"); and, the Indiana Coal Council, Inc., ("Coal Council"). CAC, IIG, STV, Valley Watch, Sierra Club, Nucor, IWF, CATF and the Coal Council are collectively referred to as "Intervenors." CAC, STV, Valley Watch and Sierra Club are collectively referred to as the "CAC" throughout this Order.

[1] The Commission notes that the Verified Petition in this Cause was originally filed jointly with Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren") with Vectren pursuing approval for 20% ownership of the IGCC Project. On June 4, 2007, Vectren filed a Motion to Suspend Procedural Schedule as it Relates to Vectren's Request for Relief, which was granted by the Presiding Officers. On August 9, 2007, Vectren filed a Motion to Dismiss its request for relief in Cause No. 43114. The Commission hereby grants Vectren's request and dismisses its request for relief in this Cause. As Duke Energy Indiana's request included up to 100% ownership of the IGCC Project, we find that consideration of the issues in this matter can properly proceed without participation by Vectren. Accordingly, this Order addresses the requested relief only as it relates to Duke Energy Indiana.

At the Evidentiary Hearing the Petitioner presented the testimony of Mr. James E. Rogers, President and Chief Executive Officer of Duke Energy Corporation; Ms. Kay Pashos, President of Duke Energy Indiana, Inc.; Dr. Norman Shilling, Product Line Leader for Integrated Gasification Combined Cycle Power Block for GE Energy; Mr. Robert D. Moreland, General Manager, Analytical & Investment Engineering, Duke Energy Shared Services, Inc.; Ms. Diane L. Jenner, Director, Integrated Resource Planning Duke Energy Shared Services, Inc.; Mr. John L. Stowell, Vice President, Environmental, Health and Safety Policy, Duke Energy Shared Services, Inc.; Mr. Judah Rose, Managing Director of ICF International ("ICF); Mr. Steven M. Fetter, President, REGULATION UnFETTERED; Mr. John J. Roebel, Group Vice President, Engineering and Technical Services, Duke Energy Shared Services, Inc.; Mr. Stephen M. Farmer; Mr. Dennis M. Zupan, Senior Project Director for the Edwardsport Project; Mr. James Lefeld, Director of Alternative Energy for Duke Energy Shared Services, Inc.; Ms. Darlene S. Radcliffe, Director, Environmental Technology and Fuel Policy, for Duke Energy Shared Services, Inc.; and Ms. Lynn Good, Vice President and Treasurer of Duke Energy Corporation.

Intervenor Clean Air Task Force and the Indiana Wildlife Federation presented the testimony of Mr. John Thompson, Director of Coal Transition Project of the Clean Air Task Force; Mr. L. Stephen Melzer, Owner, Melzer Consulting; Mr. S. Julio Friedmann, Carbon Management Program APL, Lawrence Livermore National Laboratory; and, Mr. Douglas H. Cortez, Managing Director, Hensley Energy Consulting. Intervenor Indiana Coal Council, Inc., presented the testimony of its President, Mr. J. Nathan Noland. The Indiana Industrial Group presented the testimony of Mr. Michael Gorman, Consultant in the field of public utility regulation and managing principal in the firm of Brubaker & Associates, Inc. ("BAI") and Mr. Nicholas Phillips, Jr., Consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc. The Citizen's Action Coalition presented the testimony of Mr. Grant S. Smith, its Executive Director. Interevenors Citizens Action Coalition of Indiana, Inc., Save the Valley, Valley Watch and the Sierra Club collectively presented the testimony of Mr. Bruce Biewald, President, Synapse Energy Economics, Inc.; Mr. Robert M. Fagan, Senior Associate, Synapse Energy Economics, Inc.; Philip Mosenthal, Partner, Optimal Energy, Inc., a consultancy specializing in energy efficiency and utility planning; and, David A. Schlissel, Senior Consultant, Synapse Energy Economics, Inc.

The Indiana Office of the Utility Consumer Counselor presented the testimony of Mr. Wes R. Blakley, Principal Utility Analyst; Ms. Barbara A. Smith, Utility Analyst; and, Ms. Joan M. Soller, Director, Electric Division.

Following the Evidentiary Hearing the Commission conducted a public Field Hearing on Wednesday August 29, 2007. The Field Hearing began at 6:00 p.m., EDT at the Showers Center City Hall, City Council Meeting Room, 401 N. Morton, in Bloomington, Indiana, and concluded at approximately 11:45 p.m. EDT. The Field Hearing was attended by hundreds of interested individuals who offered written and oral testimony, in favor and in opposition to the IGCC Project, into the record of this proceeding.

Those in attendance at the Field Hearing included several State Representatives; citizens from the town of Edwardsport, Indiana and other citizens from Knox County, Indiana; and citizens from surrounding counties and communities from the proposed plant site including residents of Bloomington, Indiana. In addition to receiving oral and written comments from individuals in attendance at the Field Hearing, hundreds of additional individual written comments and correspondence were submitted into the record of this Cause. Comments at the Field Hearing generally ranged from overall support for the IGCC Project based on needed generation capacity in the state of Indiana and the IGCC Project's ability to provide for economic development in Knox County, Indiana. Those opposed to the IGCC Project generally expressed environmental concerns and indicated that Duke Energy Indiana should pursue renewable forms of generation and increase its focus on conservation. All evidence and exhibits introduced at the Field Hearing were admitted into the record of this proceeding.[2]

Following the receipt of all evidence, and in preparation for taking final action on an order subject to judicial review, the Commission convened a publicly noticed Executive Session in this matter pursuant to IC 8-1-1-5(f). The Executive Session was held on Friday, November 16, 2007, at 10:00 a.m. in the Board Room of the Indiana Utility Regulatory Commission, 101 West Washington Street, Suite 1500 East, Indianapolis, Indiana. Following the Executive Session, the Order in this Cause was placed on the Commission's publicly noticed Final Agenda for the Commission's Conference scheduled for November 20, 2007.

On November 19, 2007, Intervenors Citizen's Action Coalition, Inc., Save the Valley, Inc., Valley Watch, Inc., and the Sierra Club, Inc., filed a *Verified Motion to Reopen Record and a Verified Brief in Support of Motion to Reopen Record* (collectively referred to as the "Motion"). In their Motion, filed pursuant to 170 IAC 1-1.1-22, these Intervenors requested that the Commission reopen the record in this proceeding for the purpose of taking additional evidence. As set out in the Motion, these parties contend that changes in fact and law occurred after the hearing, which are material, could not have been anticipated, and would change the outcome of this proceeding. The Commission has reviewed the Motion and finds that it does not satisfy the criteria set forth in 170 IAC 1-1.1-22. Therefore the Commission hereby denies the Motion.[3]

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[2] Additionally, on October 30, 2007, the Presiding Officers issued a Docket Entry in which they provided for the submission of a response by the Citizen's Action Coalition, Save the Valley, Valley Watch, and the Sierra Club, to certain information submitted to the Commission by Duke Energy Indiana. On November 7, 2007, the Citizen's Action Coalition, Save the Valley, Valley Watch, and the Sierra Club filed their *Response and Exhibits to Ex Parte Communications of Duke Energy Indiana* ("Response"). On November 13, 2007, Duke Energy Indiana submitted a *Reply* to the Response. These additional filings have been made part of the record in this Cause and have been considered by the Commission.

[3] 170 IAC 1-1.1-22 states in relevant part that:

(a) At any time after the record is closed, but before a final order is issued, any party to the proceeding may file with the commission and serve upon all parties of record a petition to reopen the proceeding for the purpose of taking additional evidence.

(b) A petition to reopen the record shall set forth clearly the facts claimed to constitute grounds requiring reopening of the proceeding, including the following:

(1) Material changes of fact or law alleged to have occurred since the conclusion of the hearing.

(2) The reason or reasons such changes of fact or law could not have been reasonably foreseen by the moving party prior to the closing of the record.

(3) A statement of how such changes of fact or law purportedly would affect the outcome of the proceeding if received into evidence.

(4) A showing that such evidence will not be merely cumulative.

A petition to reopen the record shall be verified or supported by affidavit.

(c) Within ten (10) days following the service of such petition to reopen upon all parties to the proceeding, any other party may file a response to the petition unless the presiding officer shall prescribe a different time. Any reply to such responses shall be filed within seven (7) days following service of the response unless the presiding officer shall prescribe a different time....

The Commission, having examined the entirety of the record in this matter and being duly advised in the premises, now finds that:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of all public hearings conducted herein was given and published by the Commission as required by law. Duke Energy Indiana is a public utility as defined in IC 8-1-2-1 and is subject to regulation by the Commission in the manner and to the extent provided for in the Public Service Commission Act, IC 8-1-2. The Commission has jurisdiction over Duke Energy Indiana and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Duke Energy Indiana is an Indiana corporation with its principal office located at 1000 East Main Street, Plainfield, Indiana. The Company is engaged in the business of supplying electric utility service to the public in the State of Indiana. Duke Energy Indiana owns, operates, manages and controls plant, property and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. It directly supplies electric energy to over 760,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. It also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, and to other public utilities which in turn supply electric utility service to numerous customers in areas not served directly by Duke Energy Indiana

3. **Relief Requested and Overview of IGCC Technology.** In this proceeding, Duke Energy Indiana has proposed to construct an IGCC Project with a capacity of approximately 630 megawatts ("MW"). The proposed IGCC Project will be designed to use Indiana bituminous coal from the geologic formation known as the Illinois Basin. The IGCC Project will be located on approximately 220 acres of land adjacent to the existing Edwardsport Generating Station, located on the White River, in the town of Edwardsport, Knox County, Indiana. Pet. Ex. No. 4, p. 4 (Moreland Direct).

The existing Edwardsport station was constructed in 1918 with the "old plant" units being retired and dismantled prior to 1960. The existing generating units were constructed predominantly in the 1940s. The station has a nominal total 160 MW nameplate rating for the three generators. Boiler #6 is an oil-fired steam generator and boilers #7-1, #7-2 and #8 are coal-fired steam generators. Coal burned at the Edwardsport Generating Station is Illinois Basin high sulfur coal mined almost entirely in Indiana. In conjunction with the completion of construction and the start up of the IGCC Project Duke Energy Indiana will retire the existing generating station and salvage any remaining usable equipment. The Petitioner indicated that it expects to promptly demolish the stack and precipitators and any remaining structures that are determined not to be useful for the IGCC Project. Pet. Ex. No. 12, p. 3-4 (Roebel Direct).

The IGCC Project proposed in this Cause will utilize a gasification process to convert bituminous coal, at high pressure and temperatures in an oxygen-controlled atmosphere into a combustible gas, called synthesis gas or "syngas." Syngas is created by finely grinding coal, mixing it with water, and feeding the slurry to a gasifier along with oxygen from a cryogenic air separation unit. The highly pressurized coal slurry and oxygen react to produce raw syngas that consists primarily of hydrogen and carbon monoxide. Inside the gasifier, the syngas is separated from slag (primarily ash in the coal) and is further cleaned by removing sulfur and other contaminants. The raw syngas from the gasifier is partially cooled by producing high pressure saturated steam that is then superheated and supplied to a steam turbine to generate power. Once created, syngas is used as fuel for combustion turbine generating units to produce electricity. Pet. Ex. No. 4, p. 4 (Moreland Direct).

In January 2005, the Company entered into a Technical Services Agreement with GE and Bechtel (the "Feasibility Study") to study the technical feasibility of building an IGCC plant at the Edwardsport Station. The study included a technical scope description, services to be supplied, projections of plant performance, including heat rate and environmental emissions, as well as a preliminary cost estimate. At the same time the Company also undertook site specific activities related to such matters including the review of the availability and costs associated with natural gas, electric system interconnection, land acquisition, and coal handling. *Id.* at 6-7.

The Feasibility Study did not identify any fatal flaws regarding the proposal and in the summer of 2005 the Company proceeded with the next phase of its investigation, consisting of the front-end engineering and design study (the "FEED Study")[4]. In addition, to further site specific studies intended to quantify the scope and cost of the entire IGCC Project, the Company and Vectren executed a second Technical Services Agreement with GE/Bechtel in February, 2006 (the "FEED Study Agreement"). The FEED Study Agreement required GE/Bechtel to develop a cost estimate for the scope of work proposed by GE and Bechtel, based on engineering documents that identified the scope of work upon which a final contract would be based. The FEED Study Agreement also covered supporting information required to apply for and ultimately obtain the necessary environmental permits, regulatory approvals, a contracting approach for construction of the IGCC Project, and information necessary to apply the reference plant design being developed by GE/Bechtel to the Edwardsport site. *Id.* at 8-9.

Pursuant to the Commission's Prehearing Conference Order dated December 13, 2006, the Company filed its FEED Study Report with the Commission, supported by the written verification of Mr. Zupan, on April 2, 2007. The FEED Study Report provided a description of the numerous investigations undertaken by the Company and GE/Bechtel for the Project including value engineering studies, updated plant performance information, the Company's updated cost estimate and schedule, and a summary of the Company's going forward contracting approach.

Based upon the FEED Study Report, the Company concluded that the IGCC technology developed to meet Duke Energy Indiana's objectives under the GE/Bechtel Alliance work performed in association with this study represents a product that will deliver 630 megawatts of reliable power with superior environmental performance at a thermal efficiency equal to or better than supercritical pulverized coal technology. Pet. Ex. No. 20-A. The FEED Study Report concluded that "the Edwardsport IGCC Project provides the best option for acquiring baseload generation in a timely manner to meet the needs of our customers." The FEED Study Report, including the confidential pages, was formally introduced as part of Mr. Zupan's rebuttal testimony. Pet. Ex. No. 20-A; Pet. Ex. No. 20 (Zupan Rebuttal).

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[4] The Company, together with Vectren, sought cost recovery for the FEED Study in Cause No. 42894. As a result of a Settlement Agreement entered into with the OUCC, the Commission entered an order on July 26, 2006, authorizing, among other matters, the ability of the Company and Vectren to fully recover their costs for the FEED Study in the event that a CPCN order is issued and the IGCC plant is built, and the recovery of 50% of FEED Study costs up to $15 million of total costs, if the Company and Vectren do not proceed forward with the IGCC Project.

A. History of Coal Gasification. By the early 1900s, commercial coal gasification was commonly used in the United States and Europe to provide cities with gas for streetlights and domestic consumption. The testimony presented in this matter indicates that coal gasification is currently being utilized in the refinery and chemical industries and has been used for various purposes for a number of years. However, despite this long history and the use of coal gasification in other industries, two advancements were necessary before coal gasification could be used with gas turbine power plants (the IGCC technology). First, was the ability to clean the syngas to extremely low levels of contaminants to avoid corrosion and erosion of the hot gas path. Second, advancements in turbine technology were necessary to allow turbines to combust lower Btu IGCC fuels. Pet. Ex. No. 3, pp. 5-6 (Shilling Direct).

B. Overview of IGCC Generation Projects. Despite the initial hurdles regarding the use of coal gasification in turbine power plants, following much testing and refining, a 120 MW Cool Water Plant was completed in California in 1984. In the 1990's, following additional advances in technology, two more IGCC facilities were constructed, the Tampa Electric Company's 250 MW Polk Power Station in Lakeland, Florida, and the 262 MW Wabash River Generating Station ("the Wabash River Repowering Project" or "Wabash River Generating Station") in Indiana. The Polk Power Station has been operating since 1996 and is part of the Department of Energy's ("DOE") Clean Coal Technology program. *Id.*

Prior to its recent purchase by Duke Energy, PSI Energy, Inc., (now Duke Energy Indiana) was directly involved in the Wabash River Repowering Project in the early 1990s, along with Destec Energy, Inc. The Wabash River Repowering Project was partially funded by the DOE and, as initially developed, used syngas from a coal gasifier as fuel for a combustion turbine. According to testimony presented in this matter, the Wabash River Generating Station is currently in operation and is one of the cleanest solid fuel power plants in the world. Pet. Ex. No. 4, pp. 4-5 (Moreland Direct). The Company's knowledge and experience gained from operating the Wabash River Repowering Project is being utilized in the development of the much larger IGCC Project. Mr. Dennis Zupan, the Senior Project Director for the IGCC Project, was the project engineer for the Wabash River Repowering Project and Mr. Jack Stultz, who will be the plant manager for the completed Edwardsport IGCC Project, was the operations manager for the Wabash River Repowering Project.

The testimony presented in this matter indicates that the benefits of IGCC technology in the generation of electricity include lower criteria emissions; production of marketable byproducts instead of waste; over 90% mercury capture; and lower water consumption than pulverized coal plants. In addition, the pre-combustion cleanup of coal provides a flexible approach to economically capture carbon as may be necessary to comply with future regulatory requirements.

4. <u>Overview of Applicable Laws and Statutory Framework for Consideration of the Issues in this Matter</u>. The Petition filed in this matter is governed by several Indiana Code provisions that must be examined by the Commission in reaching a determination in this Cause. A general overview of these statutory provisions is set forth as follows:

A. Powerplant Construction Act. Under IC 8-1-8.5-2, a public utility may not begin construction, purchase, or lease of any facility for the generation of electricity without first obtaining a certificate of public convenience and necessity ("CPCN") from the Commission.

Pursuant to IC 8-1-8.5-4 the Commission, in acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, shall take into account various enumerated alternatives regarding the Petitioner's current and potential arrangements with other electric utilities for: (a) the interchange of power; (b) the purchase of power; (c) the pooling of facilities; (d) joint ownership of facilities; and other methods of providing reliable, efficient, and economical electric service, including; (e) the refurbishment of existing facilities; (f) conservation and load management; and (g) cogeneration and renewable energy sources. In accordance with IC 8-1-8.5-4, a petitioner must fully address the enumerated alternatives in order for the Commission to make an informed decision as to whether a pending proposal is in the public interest. The statute does not limit the Commission's discretion to weigh the importance of each alternative in determining the public interest.

Under IC 8-1-8.5-5, an application for a CPCN may only be granted after a hearing, and if the Commission has: (1) approved the estimated construction, purchase, or lease costs; (2) made a finding that either such construction, purchase, or lease will be consistent with the Commission's plan for expansion of electric generation capacity, or that the construction, purchase, or lease will be consistent with a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility; (3) made a finding that the public convenience and necessity require or will require the construction, purchase or lease of the facility; and (4) made a finding that the facility, if it is a coal-consuming facility, utilizes Indiana coal or is justified, because of economic considerations or governmental requirements, in using non-Indiana coal.[5]

B. Indiana's Clean Coal Technology Certificate Statute. IC 8-1-8.7-1 defines "clean coal technology" as a technology:

(1) That is used in a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and

(2) That either:

(a) Is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or

(b) Has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989.

Pursuant to IC 8-1-8.7-3, as applicable to this Cause, a public utility may not use clean coal technology at a new or existing electric generating facility without first applying for and

[5] We recognize that in *General Motors Corp. v. Indianapolis Power & Light Co.*, 654 N.E.2d 752 (Ind. Ct. App. 1995), the Court of Appeals ("Court") declared that a portion of IC 8-1-2-6.6 relating to Indiana coal violates the Commerce Clause of the United States Constitution. The Court severed the unconstitutional provision from the remainder of the statute which was held to be valid and effective. The Court stated that if a plan "is found by the Commission to be the option best fitting the non-protectionist criteria in the statute, no bar exists to its approval on the basis that it includes the use of Indiana coal. . . ." Although we find that the proposed IGCC Project will allow Petitioner to continue the use of Indiana and Illinois Basin coal, in accordance with the *General Motors* case, we do not treat this factor as a prerequisite for Duke Energy Indiana's requested relief in this case.

obtaining from the Commission a certificate that states that the public convenience and necessity will be served by the use of clean coal technology. This chapter does not relieve a public utility of the duty to obtain a certificate under IC 8-1-8.5 if the utility is proposing the use of clean coal technology as a part of the construction of an electric generating facility. However, IC 8-1-8.7-10(b) provides that a public utility seeking a certificate under IC 8-1-8.5, and this chapter, for one (1) project may file a joint application for both certificates and that the Commission shall jointly consider both certificates.

In accordance with IC 8-1-8.7-3, the Commission shall issue a certificate of public convenience and necessity under this chapter if it finds that a clean coal technology project offers substantial potential of reducing sulfur or nitrogen based pollutants in a more efficient manner than conventional technologies in general use as of January 1, 1989. For purposes of this chapter, a project that the United States Department of Energy has selected for funding under its Innovative Clean Coal Technology program and is finally approved for funding after December 31, 1988, is not considered a conventional technology in general use as of January 1, 1989.

When determining whether to grant a certificate under IC 8-1-8.7-3 the Commission shall examine the following factors:

(1) The costs for constructing, implementing, and using clean coal technology compared to the costs for conventional emission reduction facilities.
(2) Whether a clean coal technology project will also extend the useful life of an existing electric generating facility and the value of that extension.
(3) The potential reduction of sulfur and nitrogen based pollutants achieved by the proposed clean coal technology system.
(4) The reduction of sulfur nitrogen based pollutants that can be achieved by conventional pollution control equipment.
(5) Federal sulfur and nitrogen based pollutant emission standards.
(6) The likelihood of success of the proposed project.
(7) The cost and feasibility of the retirement of an existing electric generating facility.
(8) The dispatching priority for the facility utilizing clean coal technology, considering direct fuel costs, revenues and expenses of the utility, and environmental factors associated with byproducts resulting from the utilization of the clean coal technology.
(9) Any other factors the commission considers relevant, including whether the construction, implementation, and use of clean coal technology is in the public's interest....

IC 8-1-8.7-3(b)

C. **Hearings and Additional Requisite Findings.** Pursuant to IC 8-1-8.7-4, as a condition for receiving the certificate required under IC 8-1-8.7-3, an applicant must file an estimate of the cost of constructing, implementing, and using clean coal technology and supportive technical information in as much detail as the commission requires. Under this statute, the Commission is required to hold a public hearing on each application. A certificate shall be granted only if the commission has: (1) made a finding that the public convenience and necessity will be served by the construction, implementation, and use of clean coal technology;

(2) approved the estimated costs; (3) made a finding that the facility where the clean coal technology is employed: (A) utilizes and will continue to utilize Indiana coal as its primary fuel source; or (B) is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal; after the technology is in place; and (4) made a finding on each of the factors described in the enumerated sections of this chapter, including the dispatching priority of the facility to the utility.

D. Overview of Statutory Determinations Regarding Clean Coal Technology. Pursuant to IC 8-1-8.8-1(a), the Indiana General Assembly has stated, with respect to Utility Generation and Clean Coal Technology, that:

(1) Growth of Indiana's population and economic base has created a need for new energy production or generating facilities in Indiana.[6]
(2) The development of a robust and diverse portfolio of energy production or generating capacity, including coal gasification and the use of renewable energy resources, is needed if Indiana is to continue to be successful in attracting new businesses and jobs.
(3) Indiana has considerable natural resources that are currently underutilized and could support development of new energy production or generating facilities, including coal gasification facilities, at an affordable price.
(4) Certain regions of the state, such as southern Indiana, could benefit greatly from new employment opportunities created by development of new energy production or generating facilities utilizing the plentiful supply of coal from the geological formation known as the Illinois basin.
(5) Technology can be deployed that allows high sulfur coal from the geological formation known as the Illinois Basin to be burned or gasified efficiently while meeting strict state and federal air quality limitations. Specifically, the state should encourage the use of advanced clean coal technology, such as coal gasification.
(6) It is in the public interest for the state to encourage the construction of new energy production or generating facilities that increase the in-state capacity to provide for current and anticipated energy demand at a competitive price.

The General Assembly further indicated in IC 8-1-8.8-1(b) that the purpose of this chapter is to enhance Indiana's energy security and reliability by ensuring that: (1) Indiana's energy production or generating capacity continues to be adequate to provide for Indiana's current and future energy needs, including the support of the state's economic development

[6] IC 8-1-8.8-8 defines a "new energy generating facility" as a generation or coal gasification facility, in relevant part as a facility that: (1) produces energy primarily from coal or gases from coal from the geological formation known as the Illinois Basin; (2) is a newly constructed or newly repowered energy generation plant or newly constructed generation capacity expansion at an existing facility dedicated primarily to serving Indiana retail customers. Additionally, under this statutory provision, the term includes the transmission lines, gas transportation facilities, and associated equipment employed specifically to serve a new energy generating or coal gasification facility.

efforts; (2) The vast and underutilized coal resources of the Illinois Basin are used as a fuel source for new energy production or generating facilities; (3) The electric transmission and gas transportation systems within Indiana are upgraded to distribute additional amounts of electricity and gas more efficiently; (4) Jobs are created as new energy production or generating facilities are built in regions throughout Indiana.

E. Financial Incentives that Provide for the Timely Recovery of Costs through the Utilization of Rate Adjustment (Tracking) Mechanisms. Under the provisions set forth in IC 8-1-8.8-12(a) the Commission shall provide financial incentives to eligible businesses for new energy producing and generating facilities in the form of timely recovery of the costs incurred in connection with the construction, repowering, expansion, operation, or maintenance of the facilities. Pursuant to IC 8-1-8.8-12(b), an eligible business seeking authority to timely recover the costs described in subsection (a) must apply to the Commission for approval of a rate adjustment mechanism (more commonly referred to as a "tracker") in the manner determined by the Commission.

As provided in IC 8-1-8.8-12(c) an application for such financial incentives must include: (1) a schedule for the completion of construction, repowering, or expansion of the new energy generating or coal gasification facility for which rate relief is sought; (2) copies of the most recent integrated resource plan filed with the Commission, if applicable; (3) the amount of capital investment by the eligible business in the new energy generating or coal gasification facility; and (4) other information the Commission considers necessary.

The Commission shall allow an eligible business to recover the costs associated with qualified utility system property[7] if the eligible business provides substantial documentation that the expected costs associated with qualified utility system property and the schedule for incurring those costs are reasonable and necessary. IC 8-1-8.8-12(d). A tracking mechanism proposed by an eligible business under this section may be based on actual or forecasted data. However, if forecast data is used, the retail rate adjustment mechanism must contain a reconciliation mechanism to correct for any variance between the forecasted costs and the actual costs. IC 8-1-8.8-12(f).

Additionally, IC 8-1-8.8-11(a) provides for review and consideration of additional financial incentives and indicates that the Commission shall encourage clean coal and energy projects by creating the following financial incentives if the projects are found to be reasonable and necessary: (1) The timely recovery of costs incurred during construction and operation of clean coal and energy projects described in section 2(1) or 2(2) of this chapter; (2) The authorization of up to three (3) percentage points on the return on shareholder equity that would otherwise be allowed to be earned on projects described in subdivision (1); (3) Financial incentives for the purchase of fuels produced by a coal gasification facility, including cost recovery and the incentive available under subdivision (2); (4) Financial incentives for projects to develop alternative energy sources, including renewable energy projects; (5) Other financial incentives the Commission considers appropriate.

[7] IC 8-1-8.8-5 defines costs associated with qualified utility system property as capital, operation, maintenance, depreciation, tax costs, and financing costs of or for qualified utility system property.

While the foregoing statutory provisions include a number of financial incentives that may be considered and approved, either collectively or individually by the Commission, IC 8-1-8.8-15 allows the Commission to monitor compliance with any such incentives awarded. Pursuant to the specific authority provided under this statutory provision, in the event that the Commission approves a project and determines that an incentive is appropriate, it may review any project approved under this chapter to determine that the project continues to comply with the Commission's order initially approving incentives under this chapter. The Commission may revoke any incentive approved in the order if the Commission finds that the project no longer complies with the provisions of the order concerning the incentive.

F. Ongoing Review of Construction and Costs. In this proceeding the Petitioner has requested ongoing review of the construction and costs associated with the IGCC Project. IC 8-1-8.7-7 governs such a request and indicates in relevant part that, in addition to the Commission's obligation to generally review the continuing need for the clean coal technology system under construction under IC 8-1-8.7-5, the Commission shall at the request of the public utility maintain an ongoing review of that construction as the construction proceeds. Under this provision, the applicant shall submit each year during construction, or at other times as the Commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction. The Commission must hold a public hearing before it may approve or deny a proposed increase in the cost estimates for the implementation, construction, or use of clean coal technology.

In addition, pursuant to IC 8-1-8.7-5, when in the opinion of the Commission changes in the estimate of the cost or the need for clean coal technology occur, the Commission shall immediately commence a review of the certificate granted under this chapter to determine if public convenience and necessity will be served by the implementation of the technology. If the Commission finds that implementation of the technology will not serve the public convenience and necessity, the Commission may modify or revoke the certificate.

However, despite possible action by the Commission under IC 8-1-8.7-5, recovery of costs from ratepayers is assured under the provisions set-forth in IC 8-1-8.7-6. Under this provision, if a public utility cancels the implementation of the technology as a result of the modification or revocation of a certificate by the Commission under IC 8-1-8.7-5, the public utility may recover the amount of its investment in the technology, along with a reasonable return on the unamortized balance. The utility may not recover on amounts expended in excess of the cost estimates approved by the Commission under IC 8-1-8.7-4 of this chapter unless the utility can prove to the Commission that those expenditures were necessary and prudent. The recovery must be made over a reasonable period of time through rates charged by the public utility. A recovery may not be made if there was fraud, concealment, or gross mismanagement on the part of the public utility.

5. <u>Overview of Issues Presented in this Cause</u>. In undertaking our analysis and review of the specific statutory provisions that govern our consideration of the issues in this matter, we will examine the testimony presented on an issue-by-issue basis. Our review will begin with consideration of the various specific issues under Indiana's CPCN and Clean Coal Technology Certificate Statutes and Duke Energy Indiana's request for financial incentives and will then progress to additional issues that must be considered in this Cause.

Duke Energy Indiana offered the testimony of Dr. Norman Shilling. Dr. Shilling explained that coal gasification technology can deliver cost-effective generation from coal while also playing an important role in meeting the environmental goals of reducing sulfur oxides, nitrogen oxides, mercury and other air pollutants. IGCC technology also generates useful byproducts in contrast to the large quantities of waste generated by conventional pulverized coal ("PC") plants. Pet. Ex. No. 3, p. 2 (Shilling Direct).

Dr. Shilling described IGCC as a cleaner coal technology that reduces traditional air emissions and particulate matter by approximately 50% compared to a state of the art PC plant. It also provides 90% or higher mercury capture independent of coal type and at a fraction of the cost of pulverized coal. He then explained that with IGCC technology, pollutants are removed from the syngas before they reach the gas turbine, which means that end-of-pipe cleanup is not necessary. Further, according to Dr. Shilling, IGCC technology efficiently removes ash, sulfur compounds, ammonia, mercury, other metals, and particulate matter from plant emissions. *Id.* at 4.

Dr. Shilling provided some examples of the emission reductions achieved by gasification projects in other locations, such as the 95% mercury removal achieved by a gasification plant in Kingsport, Tennessee and the NO_x emissions of less than 0.1 lb/million Btu achieved by the Tampa Electric Company's Polk and Duke Energy Indiana's Wabash River IGCC facilities. He further explained that sulfur is recovered from the syngas either as elemental sulfur or sulfuric acid in the pre-combustion cleanup stage – both of which are marketable industrial by-products. *Id.*

Petitioner's witness Mr. John Roebel testified that he believes the Edwardsport IGCC Project meets the definition of "clean coal technology" as used in IC 8-1-8.7. Mr. Roebel indicated that gasification was not in general commercial use for power generation in 1989. He also said the Edwardsport IGCC Project will be equipped with selective catalytic reduction ("SCRs") technology for the reduction of NO_x emissions and such SCRs were not in general commercial use in the United States on large coal-fired facilities in 1989. Mr. Roebel further indicated that SCRs have not been used on IGCC plants using coal for a feed stock. According to Mr. Roebel, IGCC technology is capable of removing over 99% of the sulfur and will dramatically reduce NO_x emissions, even without the addition of SCRs. In 1989, Mr. Roebel noted that there was no "conventional technology" for reducing NO_x in general use in the United States. Pet. Ex. No. 12, pp. 5-7 (Roebel Direct).

The evidence presented on this issue was not disputed by the parties and demonstrates that IGCC technology and the accompanying SCRs were not in general commercial use prior to January 1, 1989, and that the IGCC technology to be used in the Edwardsport IGCC Project received DOE funding after 1989. The evidence also demonstrates that the utilization of IGCC technology will result in substantial reductions in sulfur and nitrogen based pollutants by employing a technology that was not in general commercial use as of 1989. In addition, the Edwardsport IGCC Project will utilize Indiana coal as its primary energy source. Therefore, the Commission finds that the Edwardsport IGCC Project constitutes clean coal technology as defined in Ind. Code 8-1-8.7-1.

6. <u>Overview of Consideration of Factors under IC 8-1-8.7-3(b)</u>. Having determined that the Edwardsport IGCC Project constitutes clean coal technology, we now turn to the factors that we must consider in reviewing a request for a clean coal technology certificate under IC 8-1-8.7-3(b).

A. **The Costs for Constructing, Implementing, and using Clean Coal Technology Compared to the Cost for Conventional Emission Reduction Facilities.** Mr. Roebel testified that the IGCC technology is capable of removing over 99% of the sulfur and will dramatically reduce NO_x emissions, even without the additions of the SCR. The Edwardsport IGCC Project will have a Selexol acid gas removal system and a Clauss process sulfur recovery system which removes and collects sulfur as a salable byproduct. Mr. Roebel estimated the cost of this system to be about $147/kW (in 2006 dollars), with operating costs of approximately $0.87/MWh. Mr. Roebel contrasted these costs with the CG&E's Zimmer Station which began operation in 1989 with then state-of-the-art scrubbers. The Zimmer scrubbers could remove 91% of the sulfur at a capital cost of $158/kw (in 1990 dollars) and an operating cost of $2.04/MWh in 1992. Pet. Ex. No. 12, pp. 6-7 (Roebel Direct).

B. **Extension of the Useful Life of an Existing Generating Facility**. The Edwardsport IGCC Project will not extend the useful life of the Edwardsport generating units currently in use at the Edwardsport Generating Station. Mr. Roebel testified that these units will be retired in connection with completion of the construction and startup of the Edwardsport IGCC Project and will be dismantled. *Id.* at 4.

C. **Potential Reduction of Sulfur and Nitrogen Based Pollutants and Reduction of Sulfur and Nitrogen Based Pollutants by Conventional Technology.** Mr. Moreland testified that the 630 MW Edwardsport IGCC Project, operating 100% of the time will emit approximately 2200 tons annually of sulfur dioxide ("SO_2"), NO_x and particulates, combined. He said that IGCC technology is capable of 0.014 lbs/MMBtu of SO_2 (approximately 99.7% removal). He also said that IGCC technology is capable of 0.02 lbs/MMBtu of NO_x with an SCR installed. The IGCC technology particulate rate will be about 0.007 lbs/MMBtu. Finally, IGCC technology can remove over 90% of mercury in coal. Pet. Ex. No. 4, pp. 10-11 (Moreland Direct). Conversely, Mr. Moreland testified that the 160 MW Edwardsport Station operating 30% of the time emits approximately 11,000 tons annually of SO_2, NO_x and particulate emissions, combined. *Id.* As already noted, Mr. Roebel stated that the Zimmer generating station removes 91% of the sulfur emissions versus over 99% removal by IGCC technology. Pet. Ex. No. 12, p. 7 (Roebel Direct).

D. **Sulfur and Nitrogen Emission Standards.** The evidence of record demonstrates that the Edwardsport IGCC Project will reduce SO_2, NO_x, mercury and particulate emissions well below current Federal and State standards. The February 2006 New Source Performance Standards ("NSPS") limits (converted to lbs/MMBtu) for SO_2, NO_x and particulates are approximately 0.16 lbs/MMBtu, 0.12 lbs/MMBtu and 0.15 lbs/MMBtu, respectively. As previously stated, the IGCC technology is capable of 0.014 lbs/MMBtu of SO_2, 0.02 lbs/MMBtu of NO_x with a SCR, a particulate rate of 0.007 lbs/MMBtu, and 90+% removal of mercury in coal. Pet. Ex. No. 4, pp. 10-11 (Moreland Direct).

E. **Likelihood of Success of the Edwardsport IGCC Project.** The record demonstrates, as discussed further in this Order, that there is a likelihood of success for the

Edwardsport IGCC Project. Dr. Shilling testified that IGCC technology has been developed since the 1970s and GE has developed a broad IGCC product line of gas turbines with matching steam turbines. He cited the Wabash River 262 MW facility that began operating in 1995 as an example of a facility that has successfully utilized IGCC technology. Dr. Shilling believes the future of IGCC is bright with its inherent benefits that will drive its widespread adoption. He said gasification is already very successful and commercially accepted today. In his opinion, the Edwardsport IGCC Project will be successful. Pet. Ex. No. 3, pp. 6-9 (Shilling Direct).

F. Dispatching priority. Due to the efficient nature of its operations and after consideration of all costs, such as fuel and emission allowance costs, the Edwardsport IGCC Project is expected to economically dispatch quite often. Ms. Diane Jenner, Director, Integrated Resource Planning for Duke Energy Shared Services, Inc., testified that the STRATEGIST® model, a commercially available system expansion model, was used in the Integrated Resource Planning process and the results demonstrate that the Edwardsport IGCC Project would consistently be among the first units economically committed and dispatched on the Duke Energy Indiana system. Pet. Ex. No. 5, pp. 3, 25 (Jenner Direct).

G. Other factors. We find that the evidence presented in this matter demonstrates that the Edwardsport IGCC Project will provide economic and relative environmental benefits. Many of the economic benefits directly result from the efforts of Duke Energy Indiana to seek state and federal tax incentives. Mr. Noland, on behalf of the Indiana Coal Council, discussed the economic benefits that would result from the use of coal mined in the area of the Edwardsport IGCC Project in terms of permanent operational and temporary construction jobs. We also find it significant that, in addition to its relative environmental benefits, the Edwardsport IGCC Project could place Duke Energy Indiana in a favorable position in the event of future carbon regulation. We believe these additional issues are appropriate factors that should be considered under the provisions of IC 8-1-8.7-3.

7. **Overview of Consideration of Alternatives under IC 8-1-8.5-4.** IC 8-1-8.5-4 requires that the Commission, in acting upon any petition for the construction, purchase, or lease of any facility for the generation of electricity, take into account the Petitioner's current and potential arrangement with other electric utilities for: (a) the interchange of power; (b) the purchase of power; (c) the pooling of facilities; (d) joint ownership of facilities; and other methods of providing reliable, efficient, and economical electric service, including; (e) the refurbishment of existing facilities; (f) conservation and load management; and (g) cogeneration and renewable energy sources.

In accordance with IC 8-1-8.5-4, a petitioner must fully address the enumerated alternatives in order for the Commission to make an informed decision as to whether a pending proposal is in the public interest. As we noted *In re Petition of PSI Energy, Inc.*, Cause No. 41924 (*Ind. Util, Reg. Comm'n*, December 17, 2001) the statute does not require a utility to exhaust all statutory alternatives before it may request a CPCN for new capacity. *Id.* at 5. Rather, what is important is that the Commission be given enough information so that the Commission can take into account all of the enumerated alternatives in making its determination. The statute does not limit the Commission's discretion to weigh the importance of each alternative in determining the public interest. *Id.*

As many of these specific statutorily enumerated alternatives were not disputed by the parties, we present the following overview of the enumerated alternatives along with the specific testimony that addresses each issue. To the extent that issues within the specific alternatives were disputed by the parties they are discussed herein and further in the Order as necessary.

A. **The Interchange of Power.** It was generally not disputed by the parties that the testimony presented in this Cause demonstrates that Duke Energy Indiana regularly uses interchange power as it continuously dispatches its generation and makes market purchases to meet its native load customers' demand requirements. In its testimony presented in this Cause, Duke Energy Indiana indicated that it believes that hourly spot purchases are not a good substitute for, and cannot be depended upon to take the place of, firm capacity such as on-system generation and forward reliability purchases. In addition, Ms. Jenner noted that the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") does not allow such purchases to be applied toward a company's Module E reserve requirements. Pet. Ex. No. 5, p. 21 (Jenner Direct).

B. **The Purchase of Power.** It was not disputed that over the past few years, Duke Energy Indiana has relied on forward reliability purchases to help meet its native load customers' peak load requirements. The Company also considered purchased power in its 2005 Integrated Resource Plan ("IRP"), as demonstrated by the testimony of Ms. Jenner and Mr. Judah Rose. Ms. Jenner indicated that purchased power will likely continue to be a part of the Company's most economical supply portfolio for several years. *Id.*

C. **The Pooling of Facilities.** It was not disputed in this Cause, that Duke Energy Indiana presented evidence that the Midwest ISO Day 2 Market, along with East Central Area Reliability Coordination Agreement's ("ECAR") Automatic Reserve Sharing, which will be succeeded by the Midwest Contingency Reserve Sharing Group, if approved by FERC, helps to ensure that the use of existing capacity resources is maximized. Ms. Jenner testified that the current Midwest ISO market is very effective at utilizing the existing capacity resources in the region. Because of that, the Company does not believe that power pooling will provide any further benefits and therefore, is not a viable alternative to serve Duke Energy Indiana's current capacity needs. *Id.* at 21-22.

D. **Joint Ownership of Facilities.** Duke Energy Indiana presented evidence that it considered joint ownership of the IGCC Project. Ms. Jenner provided that from the early stages of the project, the Company had discussions with many other utilities in Indiana regarding potential joint ownership. Further, as discussed in this Order, Vectren initially considered and sought approval in this Cause for 20% ownership in the IGCC Project. Duke Energy Indiana included in its IRP analyses 100%, 80% and 50% ownership as alternatives. *Id.* at 22.

E. **The Refurbishment of Existing Facilities.** Mr. Roebel testified that the Company considered refurbishment of the Edwardsport Generating Station and described the Company's refurbishment or engineering condition assessment program ("ECAP"). The ECAP program is utilized by the Company to assess its existing units and the steps necessary to preserve their existing capacity. Even with this program, Mr. Roebel stated, the Company recognizes that the life of a generating unit cannot be prolonged forever. Pet. Ex. No. 12, pp. 4-5 (Roebel Direct).

F. **Conservation and Load Management.** Duke Energy Indiana presented evidence that, given the need for capacity on the Duke Energy Indiana system, additional conservation or load management programs are not a realistic substitute for the construction of the IGCC Project. Mr. James Rogers, President and CEO of Duke Energy, stated that Duke Energy Indiana first launched its comprehensive set of demand-side management programs in 1991 and since then, the Company has invested over $150 million in energy efficiency. He further stated the programs have saved approximately 654,000 MWhs of energy annually – enough to serve approximately 50,000 homes per year and have reduced the demand on the Company's system by about 160 MW. Mr. Rogers said that, according to the DOE Information Administration, Duke Energy Indiana's energy efficiency programs rank number 1 in Indiana, number 4 in ECAR/MAIN (out of 70 utilities) and in the top 6% nationally. He said that approximately 350,000 of the Company's customers have participated over the years and the cumulative bill savings for these participants has been over $300 million. Pet. Ex. No. 1, pp. 24-26 (Rogers Direct).

Dr. Richard Stevie, Managing Director, Customer Market Analytics for Duke Energy Shared Services, Inc., also estimated that the cumulative emissions reductions resulting from the Company's energy efficiency programs equal reductions in SO_2 by 54,000 tons, NO_x by 11,000 tons, carbon dioxide ("CO_2") by 6,850,000 tons, and mercury by 200 lbs. Pet. Ex. No. 8, p. 20 (Stevie Direct). Dr. Stevie then explained the different demand-side management ("DSM") programs currently in place at Duke Energy Indiana. The Company's current residential programs include: Residential Audit, Residential Low-Income Program, the Smart $aver® Program, a Photovoltaic Program, a Refrigeration Replacement Program, Energy Star®, a Residential Direct Load Control Program, and the newly approved Personal Energy Report Program. The Company's commercial and industrial incentive programs include: Lighting Incentive Plan, Energy Efficient Cooling Systems, and Energy Efficient Motors. *Id.* at 16-19.

Dr. Stevie testified that he prepared three alternate DSM impact forecasts: a high DSM impact case, an ultra high DSM impact case, and a low case. Under the ultra high DSM impact case, which assumed implementation of several new DSM programs, the Company's programs could provide an additional annual reduction of over 800,000 MWh and 179 MW in fifteen years. In sum, Duke Energy Indiana believes it has adequately considered and implemented many conservation and load management options. *Id.* at 21, 24.

CAC witness Mr. Philip Mosenthal testified that cost-effective electric efficiency programs will lower total costs and electric bills for consumers; such investments will boost the state and local economies by leaving consumers with more disposable income; and, by reducing electricity demand, the investments will reduce upward price pressure due to significant new investments in generation, transmission and distribution infrastructure. RC Ex. D, pp. 13-20 (Mosenthal Direct). Mr. Mosenthal also testified that he would like the Commission to increase the budget for Duke Energy Indiana's efficiency programs to take advantage of additional opportunities. He also indicated that California, Connecticut, Massachusetts, and Vermont are currently meeting a 1% level of savings and that Duke Energy Indiana should have an initial target of capturing savings of 1% of load each year with a budget of around 3% of electric revenue. He recommended that Duke Energy Indiana include the following efficiency programs: residential new construction; residential lighting and appliances; residential low income; residential existing home improvements; Commercial and Industrial ("C&I") new construction; C&I existing construction; and C&I products. *Id.*

CAC witness Mr. Bruce Biewald testified that, according to his calculations, the IGCC Project has a slight cost advantage over gas combined cycle and a PC unit, yet is more expensive than wind or DSM. However, when costs associated with carbon regulations are included in Mr.

Biewald's comparison, wind and DSM remain more cost-effective than the IGCC Project and a gas combined cycle unit becomes more cost-effective than the IGCC Project. RC Ex. B, pp. 37-41 (Biewald Direct).

In response, Dr. Stevie testified that Indiana is characterized in general as having lower energy prices coupled with above average per customer energy consumption. These low prices, he said, do not provide customers with motivation or incentive to reduce consumption and limits customer willingness to invest in energy efficiency. Pet. Ex. No. 23, pp. 3-8 (Stevie Rebuttal). Dr. Stevie testified on cross examination that the states cited by Mr. Mosenthal as having achieved high levels of energy savings, California, Connecticut, Massachusetts, and Vermont, have high residential rates. In fact, according to the Energy Information Administration, average residential electric rates for the month of March, 2007 for these states were 75% higher than the average residential electric rates in Indiana (and more than twice as much in the case of Connecticut and Massachusetts). Commercial and industrial electric rates were similarly listed as much higher than those of Indiana. IIG, CX 1.

Dr. Stevie also questioned the conclusion of Mr. Biewald that the levelized cost of DSM would come in at \$40/MWh. The recovery of lost margins, which was not considered by Mr. Biewald, would likely raise the cost to the ratepayer above \$40/MWh. Dr. Stevie also stated that Duke Energy Indiana has been actively involved in the Commission's investigation into DSM and in its own energy efficiency collaborative that includes the OUCC, CAC and industrial customers. He said that the Company plans to file a proceeding seeking to expand its current energy efficiency programs and that discussion of future levels of spending on energy efficiency is more appropriate for that proceeding. Ms. Pashos explained that the Company fully expected that its energy efficiency and demand response program offerings in that filing would equate to a spending level of 1% of Duke Energy Indiana's revenues. Pet. Ex. No. 17, p. 6 (Pashos Rebuttal).

Duke Energy Indiana witness Mr. Rose also testified that several of the Intervenors' witnesses overstate the potential for DSM and renewable resources in their testimony. In responding to this issue he examined past growth of 2.5% per year from 1980 to 2003 as reported by the SUFG and Midwest ISO reports of peak electricity demand growth between 2004 and 2006, and concluded that no major U.S. region has been able to prevent load growth. Pet. Ex. No. 25, pp. 4, 39-41 (Rose Rebuttal).

OUCC Witness Soller stated that Indiana utilities have not pursued demand side options as aggressively as they should and that it is her belief that the generic DSM proceeding will encourage greater commitments to demand side initiatives in the future. Public's Ex. 1, p. 13 (Soller Direct).

G. Cogeneration and Renewable Energy Sources. Duke Energy Indiana presented evidence that cogeneration and renewable energy sources are not adequate alternatives to the construction of the IGCC Project. Duke Energy Indiana witness Mr. Rogers described renewable energy sources as offering the potential for being cost-effective resource options with proper incentives in place. He stated that renewable energy sources cannot yet make a big enough impact on the Company's capacity to supply its growing baseload needs. Mr. Rogers also indicated that the Company issued a request for proposals ("RFP") in November, 2005 for a supply portfolio of energy and capacity generated by renewable and/or environmentally-friendly sustainable sources of power. Mr. Rogers testified that, after receiving the proposals, Duke

Energy Indiana entered into a 20-year agreement to purchase approximately 100 MW of wind power from the Benton County Wind Farm, LLC. Further, he said that the Company has installed one wind and 15 solar demonstration projects throughout its service territory at homes, schools and its own customer service centers. The Company also recently committed $75,000 to begin a feasibility study to use switch grass as a fuel in co-firing a coal-fired unit at Purdue University. Pet. Ex. No. 1, pp. 26-29 (Rogers Direct).

Duke Energy Indiana witness Ms. Jenner stated that the Company reviewed the available data for a number of other renewable resources, including solar. Based on the information available and the analysis performed, Duke Energy Indiana concluded that with the current state of technical development and the cost of such technologies, these options were not yet economically attractive on a utility scale within the Duke Energy Indiana territory. Ms. Jenner testified that renewable resources can provide some benefits, but are not appropriate substitutes for the capacity required at this time. Pet. Ex. No. 5, pp. 18-20 (Jenner Direct).

In developing its IRP, Duke Energy Indiana included the cogeneration capacity Duke Energy Indiana expects on its system over the period of the IRP. Duke Energy Indiana's IRP analysis also included a number of renewable resources including wind, solar, fuel cells and other renewables such as biomass and waste-to-energy. Two of the six plans chosen for further analysis in the Company's IRP process involved wind resources and one of its sensitivities considered a higher level of renewables. Indeed, the resource plan chosen had a placeholder added for a wind purchase power agreement ("PPA") in 2008, which is the start date for a 20-year PPA entered into with the Benton County Wind Farm LLC, as recently approved by the Commission in Cause No. 43096. (*Ind. Util. Reg. Comm'n*, December 6, 2006). *Id.* at 11-16.

CAC witness Robert Fagan testified that Indiana has a large, commercially viable wind energy resource with class 3, 4 and 5 wind regimes that could support wind turbine average annual capacity factors exceeding 30%, and up to at least 42% in some regions at 90 meter wind turbine hub heights. Mr. Fagan testified that TrueWind Solutions produced a report for the Indiana Department of Commerce, which demonstrated the geographical distribution of average annual wind speeds across the state. The report indicates that Indiana's best wind resources are located between Indianapolis, Kokomo and Lafayette and in Benton and White counties. Mr. Fagan said that the National Renewable Energy Laboratory estimates that Indiana's total installed capacity technical potential is 198,000 MW at 100 meter hub heights and 42,000 MW at 70 meter hub heights. RC Ex. C, pp. 6-12 (Fagan).

Mr. Fagan also looked to the Midwest ISO queue of wind generators that have applied to the Midwest ISO for transmission interconnection studies to estimate additional sources of wind energy that could be utilized by Duke Energy Indiana. As of April 16, 2007, Mr. Fagan indicated that the Midwest ISO queue consisted of almost 49,000 MW of potential wind generation in the Midwest ISO region, with over 3,000 MW in Indiana alone. While recognizing the benefits that wind generation can provide, Mr. Fagan recognized that wind energy could not be used to meet all of Duke Energy Indiana's native load because for many hours of the year, the wind turbine's output will be less than full-rated capacity. Additionally, he said that wind energy is not inherently dispatchable as is more traditional forms of generation, such as gas, oil and coal facilities. *Id.* at 16-19.

Mr. Fagan estimated that with 20% wind penetration by peak load, Duke Energy Indiana could have an additional 1,300 MW of wind installed on its system with no significant operational or reliability constraints. He also explained that 1,300 MW of wind energy would produce 3,986 GWh per year, at a capacity factor of 35%. Mr. Fagan also said that in 2006, the Midwest ISO Transmission Expansion Plan studied the possibility of 20% wind energy in the state of Minnesota and 10% wind energy throughout the Midwest ISO region. *Id.* at 21-22. Mr. Fagan maintained that the Company does not appear to recognize the vast potential and relatively attractive economics of wind generation resources. Further, he argued that Duke Energy Indiana limited the quantity of wind that could be selected by the STRATEGIST® model. According to Mr. Fagan, the Company limited the model by only allowing the cumulative maximum of a single additional 100 MW wind project over the 2006-2028 period, in addition to the 100 MW wind PPA already approved by the Commission. *Id.* at 23-24.

Mr. Fagan then testified regarding combined heat and power ("CHP"), which he described as a form of distributed generation that uses waste heat generated from the production of electricity to supply a portion of the thermal requirements of certain facilities, usually large commercial or industrial facilities. He indicated that a database maintained by Energy and Environmental Analysis shows that Indiana has approximately 2,074 MW of CHP generating capacity. Mr. Fagan also testified that according to a report by the Midwest Combined Heat and Power Application Center at the University of Illinois, Indiana has 30 installations with a total capacity of approximately 2,129 MW. Mr. Fagan further identified another study that indicated a market potential of 1,491 MW in Indiana, with much of that potential found in office buildings, schools, hospitals and nursing homes. He recommended that Duke Energy Indiana consider inventive programs to help the best candidate facilities finance and invest in cost-effective CHP systems. *Id.* at 29-33.

Duke Energy Indiana witness Mr. James Lefeld, Director of Alternative Energy for Duke Energy Shared Services, Inc., presented rebuttal testimony in response to Mr. Fagan. Mr. Lefeld testified that one must be careful when using technical potential assessments, because they do not take into account economics or other practical realities. He disagreed with Mr. Fagan's assertion that the Midwest ISO's application process indicates a current commercial potential for wind power of over 3,000 MW in Indiana and 45,000 MW in the Midwest ISO's region. He stated that going through the Midwest ISO process does not necessarily equate to either economic or installed projects as many projects in the queue are not ultimately built.

Mr. Lefeld also stated that, based on the Company's experience gained through its RFP for renewable power, the estimated wind price cited by Mr. Fagan is unrealistically low. According to Mr. Lefeld, Mr. Fagan's estimate did not fully consider delivery costs, which could be substantial, given that the better wind sites are not located in Duke Energy Indiana's service territory. Further, he said that wind prices have continued to increase from the time of the RFP due to increased competition for wind turbines. Pet. Ex. No. 22, pp. 3-8 (Lefeld Rebuttal).

Mr. Lefeld testified that wind energy is an "as available" energy source that can provide only a limited contribution to capacity relative to the amount of capacity installed because it cannot be "turned on" when electricity is needed. The clearest example of wind's inherent limitation, he said, is on a hot, humid, stagnant summer day when electric capacity is most needed and valuable. He also indicated that wind speeds are typically lowest at precisely the time of day when peak loads typically occur, making it a less valuable resource for peak periods.

On redirect examination Mr. Lefeld explained that the capacity that is available from wind generation at peak times is often lower than the annual capacity factor, and, in fact, it is possible that the wind generation may not be available in the peak hour. *Id.* at pp. 4-6.

Duke Energy Indiana witness Mr. Rose discussed the testimony of Mr. Fagan in which he contended that large amounts of wind energy could be relied upon by utilities. Mr. Rose indicated that Mr. Fagan's testimony overstates the potential for wind development, by extrapolating that by 2030, if wind were to meet 25% of Midwest ISO demand this would require approximately 85,000 to 95,000 MW of wind. Pet. Ex. No. 25, p. 41 (Rose Rebuttal).

In response to Mr. Fagan's criticism that Duke Energy Indiana used its STRATEGIST® model to limit the quantity of wind that could be selected by the model, Ms. Jenner explained that Mr. Fagan failed to consider the CO_2 scenarios the Company had analyzed. Even so, in an updated analysis the Company allowed the model to choose up to twelve 100 MW wind projects in addition to the Benton County Wind PPA Project, but the model chose only two projects, and that was in the CO_2 Scenario where wind is more likely to be economic. In new runs included in her rebuttal testimony Ms. Jenner allowed the model to choose up to a total of 1300 MW of wind, and it still only choose a total of 300 MW of wind (or 45 MW of capacity value). Pet. Ex. No. 24, p. 11 (Jenner Rebuttal).

Duke Energy Indiana witness Mr. Roebel testified that the Company has aggressively pursued economic CHP projects throughout the country, including Indiana. Duke Energy owns or manages 23 projects throughout the country with 6,514 MW, 84,380 tons of cooling capacity, and 13,210 Mlb/hour of steam capacity. He also indicated that a study cited by Mr. Fagan in support of his testimony listed Cinergy as one of three energy companies leading the way for CHP in Indiana. Pet. Ex. No. 27, p. 5 (Roebel Rebuttal). Mr. Roebel further stated that the data used by Mr. Fagan, to demonstrate the potential for CHP in Indiana, is over seven years old; does not investigate any specific customers; and is cited for technical not economic potential. Mr. Roebel reported that Duke Energy's experience is that even when a project appears economic, the customer may well be reluctant to participate. Mr. Roebel also pointed out that the study relied upon by Mr. Fagan specifically mentions that "[r]elatively low electricity rates and high natural gas prices in Indiana . . . may result in a less attractive environment for CHP in Indiana." Mr. Roebel concluded by indicating that he does not believe CHP is an acceptable substitute for the Edwardsport IGCC Project. *Id.* at 5-6.

8. <u>Commission Discussion and Findings on CPCN Alternatives</u>. As we have previously observed, the CPCN statute "requires public utilities in Indiana to evaluate and consider reasonable alternatives to installing additional generating capacity to meet the utility's forecasted probable future growth of the use of electricity and requires the Commission to consider the utility's evaluation of alternative means of meeting capacity requirements . . . .We believe that some deference should be given to a utility's judgment, provided the utility has made a reasonable, good faith effort to evaluate and consider available alternatives. . . ." In Re Petition of PSI Energy, Inc., Cause No. 39175, at pp. 3-4 (*Ind. Util. Reg. Comm'n,* May 13, 1992); In re Petition of PSI Energy, Inc., Cause No. 41924, at p. 12 (*Ind. Util. Reg. Comm'n*, Dec. 17, 2001); In re Petition of PSI Energy, Inc., Cause No. 42145 at p. 31 (*Ind. Util. Reg. Comm'n*, Dec. 19, 2002).

With respect to the statutory alternatives, the evidence shows that Duke Energy Indiana adequately considered interchange of power, pooling of facilities, joint ownership of facilities, and refurbishment of existing facilities, and that it has reasonably concluded that none of these alternatives would provide the capacity to be provided by the construction of the IGCC Project. Furthermore, the evidence indicates that Duke Energy Indiana adequately considered the purchase of power in its resource planning process and reasonably concluded that the construction of the IGCC Project was a superior alternative in terms of risk and reliability. Accordingly, we find that Duke Energy Indiana has adequately considered the purchase of power, and that its preference for the construction of the IGCC Project in lieu of reliance on purchased power is reasonable.

The evidence also shows that Duke Energy Indiana adequately considered conservation and load management alternatives in its resource planning process, and that Duke Energy Indiana reasonably concluded that conservation and load management cannot be used to substitute for or replace the capacity represented by the IGCC Project. We note that Duke Energy Indiana is currently in a Collaborative with the OUCC and some of the Intervenors, wherein an independent market potential study was conducted, and that the parties are working together toward the goal of increasing the Company's energy efficiency and demand response program offerings. We also note that Duke Energy Indiana, along with other utilities in the state and interested parties, is participating in the Commission investigation into DSM. Although evidence was presented by the CAC witnesses that the Company should be required to meet its capacity needs through increased DSM and energy efficiency programs, for purposes of this proceeding the Commission finds that Duke Energy Indiana has adequately considered conservation and load management alternatives.

Additionally, the evidence presented in this matter also indicates that Duke Energy Indiana adequately considered cogeneration and renewable energy sources in its resource planning process. Duke Energy Indiana demonstrated that, for both technical and economic reasons, cogeneration and renewable energy sources cannot be used as substitutes for the capacity of the IGCC Project. Duke Energy Indiana adequately considered wind and other renewables, and demonstrated that such resources, though promising, cannot be counted on to fulfill Duke Energy's substantial capacity need, specifically its need for baseload generation. Duke Energy Indiana reasonably concluded that the IGCC project will be a more reliable supply resource than wind for addressing baseload capacity needs. We find that Duke Energy Indiana has adequately considered cogeneration and renewable energy alternatives and that its decision to acquire needed capacity by means other than cogeneration and renewable energy sources is reasonable.

9. <u>Overview of Consideration of the Statutory Requirements Contained in IC 8-1-8.5-5 and IC 8-1-8.7-4</u>. Pursuant to IC 8-1-8.5-5, the Commission may grant a CPCN only if it has approved the estimated construction, purchase, or lease costs; has made a finding that either such construction, purchase, or lease will be consistent with the Commission's plan for expansion of electric generation capacity, or that the construction, purchase, or lease will be consistent with a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility; and has made a finding that the public convenience and necessity require or will require the construction, purchase or lease of the facility.

Additionally, pursuant to IC 8-1-8.7-4, as a condition for receiving the certificate required under IC 8-1-8.7-3, an applicant must file an estimate of the cost of constructing, implementing, and using clean coal technology and supportive technical information in as much detail as the commission requires. Under this statute, the Commission may grant a certificate if it has made a finding that the public convenience and necessity will be served by the construction, implementation, and use of clean coal technology; approved the estimated costs; made a finding that the facility where the clean coal technology is employed utilizes and will continue to utilize Indiana coal as its primary fuel source; and has made other determinations consistent with the statute.

We now address the specific evidence presented by the parties relevant to our consideration of these statutory requirements.

A. Load Forecast and Need for Additional Capacity.

1. Evidence Presented by Petitioner on the Load Forecast Issue. Dr. Stevie presented Duke Energy Indiana's 2005 and 2006 load forecasts. According to Dr. Stevie, the load forecast begins with an updated Duke Energy Indiana service area economic forecast which was prepared by Moody's Economy.com. The load forecast provides detailed projections of many aspects of the economy including: employment, income, wages, industrial production, inflation, prices and population. Using this forecast and historical Duke Energy Indiana load data an energy forecast is prepared with econometric models. Using the energy forecast, summer and winter peak demand forecasts are developed using econometric equations where peak demand is a function of economic growth, as measured by energy sales and several key weather factors. Dr. Stevie explained that the impact of historic DSM programs, implemented in Duke Energy Indiana in its service territory, is reflected in the load forecasts. Pet. Ex. No. 8, p. 5-8 (Stevie Direct).

The energy forecast projects the load required to serve: (1) Duke Energy Indiana's three retail customer classes – residential, commercial and industrial; (2) the wholesale loads of municipals and rural electric membership corporations ("REMCs") served directly by Duke Energy Indiana, including new wholesale contracts that offset expiring contracts; and (3) portions of the wholesale load requirements of the Indiana Municipal Power Agency ("IMPA") and Wabash Valley Power Association, Inc. ("WVPA"), as applicable. *Id.*

In his testimony, Dr. Stevie also compared the Company's load forecast with the State Utility Forecasting Group's ("SUFG") 2005 load forecast for the Duke Energy Indiana service territory. After making certain adjustments to reflect differing treatment of wholesale loads, the SUFG's forecasted growth for Duke Energy Indiana's retail peak load for the period 2006 to 2021 is higher than the Company's by nearly one percent. This difference is due primarily to Duke Energy Indiana's lower forecast for economic growth in its service territory. Dr. Stevie testified that if the Company's service territory economic growth is higher than reflected in the economic forecasts, the electric loads could be significantly higher than currently projected. *Id.* at 10-11.

2. OUCC and Intervenors' Evidence and Petitioner's Response Regarding the Load Forecast Issue. While the parties to this proceeding did not challenge Duke Energy Indiana's load forecasting methodology or the Company's load forecast, CAC witness Mr. Biewald testified that there were "unexplained differences" between the forecasts described by Dr. Stevie and the forecast used by Ms. Jenner in the Company's planning analyses. Mr. Biewald indicated that he believed that the differences related to Duke Energy Indiana's back up power supply obligations associated with WVPA's and IMPA's ownership interests in Gibson Unit 5 and questioned Ms. Jenner's modeling of these obligations. Mr. Biewald also expressed concern that if the Company was offering power to new wholesale customers at prices below the all-in cost of the Edwardsport IGCC Project, then retail customers would be enabling off-system sales. RC Ex. B, pp. 23, 26-29 (Biewald Direct).

In his rebuttal testimony Dr. Stevie explained that the 2005 load forecast included in his original testimony did not include certain wholesale loads such as the 70 MW firm contract with WVPA and the backup for IMPA's ownership of Gibson Unit 5. Once those adjustments are made the forecast exactly matches the forecast used for the 2005 IRP. Dr. Stevie also testified that when forecasted wholesale native load sales are added to the 2006 load forecast included in his direct testimony there are only slight differences, due to changes in the economic outlook between the load forecast used for the 2005 IRP and Dr. Stevie's 2006 load forecast. Pet. Ex. No. 23, pp. 2-3 (Stevie Rebuttal).

Ms. Pashos indicated in her rebuttal testimony that the Petitioner does not add capacity for off-system, non-native sales opportunities as implied by Mr. Biewald. Ms. Pashos pointed out that wholesale native load customers, (primarily Indiana-based cooperatives and municipal wholesale suppliers) as distinguished from off-system opportunity sales, have been an integral part of Duke Energy Indiana's system for many years, making up from 8% to 11% of the Company's load obligation. In Duke Energy Indiana's last base rate case wholesale native load was approximately 8% to 9% of total load. Accordingly, 8% to 9% of fixed production costs in that case were allocated to wholesale native load customers, not retail customers. Pet. Ex. No. 17, p. 7 (Pashos Rebuttal). As reflected in CAC Cross Examination Exhibit 15 (Confidential), new wholesale native load contracts are primarily with Indiana based wholesale suppliers, serving Indiana retail customers.

Ms. Jenner testified on rebuttal that Duke Energy Indiana's total capacity needs in the 2012-2014 timeframe are approximately 850-1000 MW, prior to the addition of any new resources, of which the need for baseload capacity is approximately 300 to 600 MWs. Pet. Ex. No. 24, p. 9 (Jenner Rebuttal). According to Ms. Jenner, the wholesale native load forecast used in her updated analysis is approximately the same as the long-time historical level of Duke Energy Indiana's wholesale native load, and is consistent with the level of wholesale native load that was included in the Company's last rate case. *Id.* at 5.

3. Commission Discussion and Findings Regarding Load Forecast. Based on the evidence presented, the Company has utilized a uniform approach to load forecasting. We find that Dr. Stevie effectively clarified and responded to the concerns expressed by Mr. Biewald. Therefore, we find that the Petitioner's load forecasting methodology and load forecasts presented in this Cause are reasonable.

B. Integrated Resource Planning Process and Need for Additional Capacity.

1. Evidence Presented by the Petitioner. Ms. Jenner stated that the goal of the IRP process is to determine an optimal combination of resources that can be used reliably and cost-effectively to meet customers' future electrical service requirements. Duke Energy Indiana's most recent 2005 IRP was submitted to the Commission on June 15, 2006, and was included as an exhibit to Ms. Jenner's testimony in this proceeding. *See,* Petitioner's Exhibit No. 5-A.

According to Ms. Jenner, the initial steps in Duke Energy Indiana's IRP process consist of development of planning objectives and assumptions and the preparation of the electric load forecast discussed herein. Major objectives of the Company's IRP process are: (1) to provide adequate, reliable and economical service to customers while meeting all environmental requirements; (2) to maintain the flexibility and ability to alter the plan in the future as circumstances change; (3) to choose a near-term plan that is robust over a wide variety of possible futures; and (4) to minimize risks such as wholesale market risks and reliability risks. Pet. Ex. No. 5, p. 8 (Jenner Direct).

Petitioner's evidence detailed how its integrated resource planning process is used to first identify the range of viable alternatives and then to narrow those choices to the best alternative. Ms. Jenner testified that the Company considers a multitude of options and combinations of options in its IRP process, such as DSM programs, environmental compliance alternatives, and supply-side alternatives. As part of the Company's screening process, in order to reduce the universe of options to a more manageable number for purposes of more detailed analysis, the potential demand-side, supply-side and environmental compliance alternatives are evaluated for their cost-effectiveness along with resources that are the most viable and cost-effective. These options are then passed on to the integration process using a commercially available, well accepted system expansion model, STRATEGIST® for further analysis. *Id.* at 3-6.

Ms. Jenner stated that the STRATEGIST® model uses the load forecast, in concert with data concerning existing generating units, demand-side resources, environmental compliance alternatives and future supply-side resource alternatives, to simulate electric production system operation. The model then dynamically analyzes the cost-effectiveness of a multitude of combinations of resource alternatives resulting from the screening analyses. This ultimately produces a number of resource expansion plans, which include environmental emission constraints that meet the prescribed reliability criteria. These resulting resource expansion plans are then ranked from lowest to highest in terms of Present Value Revenue Requirements ("PVRRs"). Normally, the model analysis produces a number of expansion plans with PVRRs that are so close that, for all practical purposes, they are identical. Therefore, the Company must apply judgment to the raw model results. The resulting combinations are reviewed by the Company in terms of risk, flexibility, availability of equipment, constructability and transmission constraints. *Id.* at 6-7.

Ms. Jenner testified that all of the generating units on the Company's system (and their operating characteristics) were included in the model, along with a number of parameters including the Company's load forecast, reliability criteria,[8] forecasted fuel, emission and market prices, [9] demand-side resources, environmental compliance alternatives and supply-side alternatives.[10] The specific supply-side alternatives included simple-cycle CTs; combined cycle units; supercritical pulverized coal units; an IGCC unit at Edwardsport along with the retirement of the existing Edwardsport 6-8 units; greenfield IGCCs; 100 MW block purchases of power from the market; a 100 MW wind purchased power agreement; and, 100 MW turnkey wind

[8] Ms. Jenner testified that the 2005 IRP used a 15-17% reserve margin (as a minimum) along with the same Loss of Load Hours ("LOLH") (annual LOLH less than 175) and Expected Unserved Energy ("EUE") (less than 0.18%) criteria the Company has been using in its past IRPs. Pet. Ex. No. 5, p. 8 (Jenner Direct).

[9] ICF provided forecasts of fuel, emission allowance and power prices. *See* Pet. Ex. No. 6 (Rose Direct).

[10] Mr. Moreland provided cost estimates and other operating information for the supply side alternatives. *See* Pet. Ex. No. 4 (Moreland Direct).

projects. The wind alternatives were based on the bids received by Duke Energy Indiana in its RFP for renewable resources. The environmental compliance alternatives included in the model were SCRs on Cayuga 1 and 2; 500 MW or 635 MW common scrubbers on Wabash River 2-6; a scrubber on Wabash River 6; precipitator upgrades on Wabash River 2-6; a common baghouse on Wabash River 2-5; and, retirements at Wabash River and Gallagher. *Id.* at 10-11.

Ms. Jenner described the major sensitivities that were analyzed under the base case conditions on a number of significantly different resource plans: higher gas price forecast; higher load forecast; lower load forecast/higher level of renewables; higher DSM; IGCC without federal incentives; a property tax abatement on a supercritical PC unit; lower capital cost of supercritical PC unit; later first in-service date for supercritical PC unit; 17% reserve margin; Clean Air Interstate Rules ("CAIR") and Clean Air Mercury Rules ("CAMR") Plus (with assumed stricter emissions caps beginning in 2014); and, CAIR/CAMR Plus with CO_2 (assumed the same stricter emissions caps in 2014 along with an assumed level of CO_2 emission allowance prices). Ms. Jenner stated that all of the sensitivity and scenario analyses showed that the plans containing either a 50% or 80% ownership of the IGCC Project appeared to be the most robust overall sensitivities and scenarios. The least cost plan in each sensitivity and scenario contained either the 80% or 50% ownership of the IGCC Project, which led to the 80% ownership of the IGCC Project being selected for the 2005 IRP. *Id.* at 12-16.

Ms. Jenner also described the resource plan selected as a result of the IRP analysis. The plan contains the DSM bundle, interruptible contracts, direct load control and PowerShare® CallOption programs and special contracts. Ms. Jenner said that the supply-side resources consist of the wind power PPA starting in 2008, the Edwardsport IGCC Project, retiring the existing units at Edwardsport and installing a CT in 2016. Further in the future, the plan consists of another CT in 2027, a 50% natural gas combined cycle unit in 2021, and a supercritical PC unit in 2023. She also indicated that the IRP includes various environmental compliance measures which were approved by the Commission in Cause Nos. 42622 and 42718 (*Ind. Util. Reg. Comm'n*, May 24, 2006). *Id.* at 16-17; Pet. Ex. No. 5-D.

Ms. Jenner also stated that the latest SUFG report shows a growing gap between projected demand and the resources to serve that demand for the state. According to Ms. Jenner, over the next five years the SUFG plan calls for a combination of new peaking, cycling, and baseload capacity or purchases from the market, and that by 2011 the baseload need for the state will be approximately 40% of the total 3540 MW requirement.

Ms. Jenner further testified that in her analyses the STRATEGIST® model shows that the Edwardsport IGCC Project is consistently among the first units economically committed and dispatched due to its efficient heat rate and low environmental emissions. She also described the various analyses performed regarding the economics of the IGCC plant with a change in tax incentives and if Vectren were to decide not to participate – all of which maintained the economic viability of the Edwardsport IGCC Project. Pet. Ex. No. 5, pp. 24-27 (Jenner Direct).

Ms. Jenner also provided Supplemental Testimony in this Cause after Duke Energy Indiana learned that the Edwardsport IGCC Project had been awarded federal investment tax credits. She described the additional analysis performed on the IGCC Project to consider the effects of the federal tax credits and the escalation of costs of alternative supply-side generating technologies, specifically supercritical pulverized coal units, natural gas simple cycle combustion units, natural gas combined cycle combustion units, and wind projects. She explained that in the base case scenario, the number 1 plan contained a natural gas combined cycle unit in 2011, but the plan containing the IGCC Project in 2011 was only 0.23% higher in PVRRs. Pet. Ex. No. 15 (Jenner Supplemental).

2. OUCC and Intervenors' Evidence and Petitioner's Response. Mr. Biewald, a witness for Intervenor CAC, criticized a number of aspects of Duke Energy Indiana's resource planning. Mr. Biewald claimed that Duke Energy Indiana used unrealistic assumptions about the capital cost and online date for Edwardsport as the Company did not use the cost estimate and schedule developed as a part of the Front End Engineering and Design ("FEED") Study. Additionally, Mr. Biewald testified that the Company failed to include the impacts of its proposed ratemaking in its analysis.

Mr. Biewald also asserted that the Company inappropriately analyzed its back-up obligations for WVPA's and IMPA's ownership shares of Gibson Unit 5, claiming that the model will not be able to differentiate between back-up power and native load obligations. According to Mr. Biewald, the Company plans to meet back-up needs as if these needs were firm, and the Company could more appropriately meet these obligations with a low cost peaking resource. According to Mr. Biewald, the Edwardsport IGCC Project would result in a clear increase in off-system power sales. Mr. Biewald further testified that Duke Energy Indiana inadequately considered renewable resources such as wind. Mr. Biewald also criticized the Petitioner for not analyzing a scenario in which Duke Energy Indiana owns 100% of the Edwardsport IGCC Project. Mr. Biewald also claimed that the CO_2 emission allowance prices the Company used to analyze future potential carbon regulation were too low. Finally, using a simple levelized cost analysis, Mr. Biewald estimated that if the Edwardsport IGCC Project were replaced by a mix of 50% wind and 50% DSM, the cost savings to Indiana customers would be approximately $1.9 billion cumulative present value dollars over the period 2011-2030. RC Ex. E, pp. 23-29 (Biewald).

Intervenor CAC witness Mr. David Schlissel testified with respect to potential CO_2 regulations and indicated that while Duke Energy Indiana utilized figures from Senator Bingaman's draft legislation as part of its sensitivity analyses, these figures do not reasonably capture the possible magnitude of greenhouse gas regulations. Mr. Schlissel indicated that he believes emission reduction requirements will likely be greater than those required by Senator Bingaman's bill and that policymakers may ultimately choose to enact both cap and trade regimes and a range of complementary energy policies. Accordingly, Mr. Schlissel concluded that Duke Energy Indiana's modeled CO_2 prices are too low and that the Company has underestimated the CO_2 costs associated with regulation. Further, he maintained that higher CO_2 costs would have a material effect on the economics of building and operating the IGCC Project. RC Ex. E, p. 12 (Schlissel Direct).

In response to this testimony, Ms. Jenner presented Duke Energy Indiana's updated analysis of the Edwardsport IGCC Project, using the estimated costs and schedule from the FEED Study. Ms. Jenner also explained that even though the STRATEGIST® model, as licensed by Duke Energy Indiana, is not a ratemaking model, in the updated analysis the Company included the effects of its ratemaking proposals to the extent that the Company was able to do so. The Company also updated other inputs, such as the capital costs of other supply side alternatives supplied by Mr. Moreland[11] and the forecast prices of gas, power and emission

[11] *See* Pet. Ex. No. 19 (Moreland Rebuttal).

allowance prices supplied by Mr. Rose.[12] Ms. Jenner also updated the level of native load to be served in recognition of the fact that the Company has executed additional firm wholesale native load contracts and that the Company's total wholesale native load is now approximately the same as Duke Energy Indiana's historical level of wholesale native load. Pet. Ex. No. 24, pp. 2-5 (Jenner Rebuttal).

Ms. Jenner testified that the results of this updated analysis were that in the base case scenario the plan containing the 80% ownership share of the Edwardsport IGCC Project was 0.11% lower in PVRR than the lowest cost plan without the IGCC. She also testified that, under the CO_2 scenario, the IGCC plan was 0.19% lower than the lowest cost plan without the IGCC (a plan that would require 450 MW of natural gas combined cycle capacity in 2011). Ms. Jenner also analyzed the scenario of Duke Energy Indiana assuming 100% ownership of the Edwardsport IGCC Project. In that case the results were that in the base case scenario the plan containing the 100% ownership share of the Edwardsport IGCC Project was 0.24% lower in PVRR than the lowest cost plan without the IGCC. She also testified that, under the CO_2 scenario, the IGCC plan was 0.13% lower than the lowest cost plan without the IGCC. *Id.* at 7.

In response to Mr. Biewald's claim that the Company could more appropriately meet its back-up power supply obligations associated with WVPA's and IMPA's ownership interest in Gibson Unit 5 with a low cost peaking resource rather than model these obligations as firm, Ms. Jenner stated that these obligations are firm contracts and have been treated as such in past Duke Energy Indiana IRPs and rate cases. The Company has included IMPA's and WVPA's Gibson 5 capacity shares as well as the load for IMPA and WVPA that correspond to their shares at a 100% load factor. Ms. Jenner also pointed out that this modeling was discussed explicitly in the 2005 IRP which is part of the record in this proceeding. *Id.* at 5.

In response to Mr. Biewald's claim that that the Edwardsport IGCC Project would result in a clear jump in off-system power sales Ms. Jenner testified that she was unable to replicate Figure 19 in Mr. Biewald's testimony showing large increases in off-system sales. According to Ms. Jenner, the model is limited to sell only 200 MW into the market, and that the Company's historical level of non-native sales is actually about twice the amount of economy sales shown in the model runs. Ms. Jenner also stated that non-firm off-system sales revenues should be included in the model because of the economies they provide to the Company's customers. *Id.* at 8-9.

Ms. Jenner next addressed Mr. Biewald's suggestion that the IGCC Project could be replaced by 50% wind and 50% DSM. If it is assumed that a wind farm contributes 15% of its nameplate capacity at the time of the summer peak, a conservative assumption, Ms. Jenner estimated that 2060 MW of installed wind capacity (or about twenty 100 MW wind farms) would be required to replace half of the total IGCC Project's capacity. She also cited studies that demonstrated that an even lower level of capacity can be expected from wind and that such resources are subject to significant variability in the capacity value provided. A lower capacity value would require even more wind farms. *Id.* at 10-11.

Ms. Jenner opined that levelized cost analyses used by Mr. Biewald are simplistic and sometimes misleading and should not be used to make final economic decisions. She further explained that Mr. Biewald's analysis compares resources on a cost per MWh basis with no

[12] *See* Pet. Ex. No. 25 (Rose Rebuttal).

regard for the capacity value of a resource, its dispatchability, or the time of day when its MWh are provided. In response to Mr. Biewald's claim that the Edwardsport IGCC Project could be replaced by a mix of 50% wind and 50% DSM and that the resulting cost savings to Indiana customers would be approximately $1.9 billion cumulative present value dollars over the period 2011-2030, Ms. Jenner testified that this assumption was based on a simplistic spreadsheet levelized cost analysis that used understated costs. According to Ms. Jenner, if this position were accepted by the Commission it would potentially leave customers short of power on hot summer afternoons. *Id.* at 11-14.

Mr. John Stowell responded to Mr. Schlissel's criticisms of the forecasted CO_2 emission allowance prices the Company used in its analysis of possible future carbon regulation. Mr. Stowell explained that while he believes that legislation regulating CO_2 will be enacted in the future he is of the opinion that Congress will be very careful to do so, particularly in the early years, in such a way as not to shock and disrupt the economy. Pet. Ex. No. 18, p. 4 (Stowell Rebuttal). In further addressing this issue, Mr. Stowell testified that the CO_2 prices he provided to Ms. Jenner for the IRP analysis followed expected prices from a draft of Senator Bingaman's bill in the early years, but that the Company increased the prices in the later years in recognition of its belief that CO_2 prices would have to increase to a level equal to the estimated cost of carbon capture and sequestration technology. *Id.*

Mr. Rose also disagreed with Mr. Schlissel's criticisms of the forecasted CO_2 emission allowance prices used by the Company and with Mr. Schlissel's forecasts of CO_2 emission allowance prices generally. Mr. Rose indicated that Duke Energy Indiana's CO_2 emission forecasts are reasonable and consistent with ICF's own forecasts. He maintained that the Intervenors overstate potential CO_2 allowance prices and fail to account for key factors which mitigate the effects of CO_2 controls on the economics of coal plants including higher natural gas prices, lower emission allowance prices for SO_2, NO_x, and mercury, lower coal prices, and the potential for extra allowance allocations. Pet. Ex. No. 25, pp. 15, 17 (Rose Rebuttal). Mr. Rose explained how ICF modeled CO_2 allowance prices, developing mild, stringent and expected CO_2 scenarios. Mr. Rose also indicated that IGCC technology has the potential for lower emissions due to higher thermal efficiency, which is in turn related to the potential for greater ease of carbon capture in IGCC facilities. *Id.* at 14, 17-24.

Mr. Rose also described what he believes are flaws in the CO_2 studies relied upon by Intervenors. For example, he said that Mr. Schlissel identified three studies of the two versions of the McCain-Lieberman bill with widely different results, but noted that Mr. Schlissel gave equal weight to each, with no view as to which is correct. Mr. Rose also noted that Mr. Schlissel excluded results from some studies without explanation and further failed to explain why one scenario from a study was accepted while others were rejected. Another key flaw of Mr. Schlissel's analysis is that although he seemed to acknowledge that gas prices are important in evaluating power sector economics, he failed to provide a gas forecast associated with his expected higher CO_2 prices. Pet. Ex. No. 25, pp. 24-30 (Rose Rebuttal). Mr. Rose concluded that Mr. Schlissel's higher CO_2 estimates, reaching $40 to $50/ton in real dollars, represent extreme views and therefore should be given little weight by decision makers. *Id.* at 37-38.

Ms. Soller testified that load forecasts and anticipated changes in generating assets support the construction of the Edwardsport project as a baseload resource. The annual growth rate of 0.6% and expected continuity of long-term contracts justify the need for baseload capacity. Ms. Soller further stated that evaluation of future power plant construction without appropriate assumptions that the future will be carbon constrained falls short of a reasonable and prudent review of regulatory issues. Public's Ex. No. 1, p. 7 (Soller Direct). In her testimony Ms. Soller also listed potential resource options to meet energy consumption needs while managing carbon dioxide emissions and utilizing renewable resources. The programs and options discussed by Ms. Soller include distributed generation; use of more efficient gas-fired generation; Energy Efficiency programs; and Demand Side Management and Demand Response programs. *Id.*

3. Commission Discussion and Findings on Petitioner's IRP Process and Need for Additional Capacity. Based on our review of the Petitioner's Integrated Resource Planning process presented in this matter, the Company has considered a wide range of alternatives using established methodologies and we find the Company's approach to this issue to be reasonable. Ms. Jenner's rebuttal testimony responds to issues presented by Mr. Biewald and Mr. Fagan regarding the Petitioner's use of the STRATEGIST® model. Duke Energy Indiana analyzed the Edwardsport IGCC Project using the updated cost and schedule from the FEED Study and modeled its proposed rate treatment within this model to the extent possible. Duke Energy Indiana's modeling of its back-up obligations with respect to IMPA's and WVPA's ownership shares of Gibson Unit 5 responds to concerns expressed by certain intervenors. Duke Energy Indiana also analyzed a 100% ownership of the Edwardsport IGCC Project scenario. Mr. Biewald's concerns regarding the Company's treatment of off-system power sales were effectively addressed by the Company in light of the limits Petitioner placed on such sales, and the fact that the model's results were significantly lower than historical levels of such sales.

With respect to our consideration of issues regarding the forecast of CO_2 emission allowance prices we find that Duke Energy Indiana effectively utilized various scenarios that analyzed the impact of possible future carbon regulation. While there was almost uniform agreement in this proceeding that CO_2 emissions will be regulated in the future, these emissions are not regulated today. Therefore, the Commission cannot assume or reasonably speculate in this proceeding regarding what, if any action, the U.S. Congress may ultimately take with respect to carbon regulation. Therefore, we find that the Petitioner's analysis of potential future CO_2 emission allowance prices is reasonable as it strikes an appropriate balance with respect to alternative scenarios that may be applicable to the future regulation of carbon emissions.

Regarding Duke Energy Indiana's load forecast and IRP process we note that the Company demonstrated a total capacity need in the 2012-2014 timeframe of approximately 850-1000 MW prior to the addition of any new resources. Of that amount, Duke Energy Indiana's analyses show a need for about 300-600 MW of baseload capacity in the same timeframe. Pet. Ex. No. 24, p. 9 (Jenner Rebuttal). We have found that the Petitioner's load forecasting and IRP process are reasonable and we conclude that Petitioner has demonstrated a need for 850 to 1000 MWs of additional generation capacity by the 2012-2014 timeframe, including a need for 300 to 600 MWs of baseload capacity. Additionally, in the most current IRP runs, the IGCC Project is included in the lowest cost PVRR plan in each scenario, including a scenario with potential carbon regulation. Based on the entirety of the record we find that Petitioner adequately considered alternative options to meet its capacity needs, and that the testimony presented in this matter demonstrates that the IGCC Project constitutes an appropriate option to meet those needs.

In summary, we find that the Petitioner's integrated resource planning methodologies appear sound and that the testimony presented by the Petitioner addresses concerns raised by certain intervenors in this proceeding. Therefore, based on the evidence and testimony presented in this Cause, we find that the planning process utilized by Duke Energy Indiana is reasonable and should be approved by the Commission.

C. IGCC Project Cost Estimate.

1. Petitioner's Evidence. Mr. Moreland described the process by which the Company prepared the cost estimate for the IGCC Project. This estimate, reflected in Petitioner's Confidential Exhibit 4-D, is based on the indicative cost estimate produced in the initial feasibility study and includes estimated costs for portions of the project that are outside the expected scope of GE/Bechtel's work. These estimated costs include the cost of the land, the cost of the transmission interconnection, costs associated with a possible rail spur, coal handling equipment, owner's costs, escalation and allowance for funds used during construction ("AFUDC"). Mr. Moreland noted that the $12.4 million estimated cost to demolish the existing Edwardsport Station, is not included in the cost estimate for the IGCC Project.

According to Mr. Moreland, the low end of the Company's confidential cost estimate was used by Ms. Jenner in developing the Company's 2005 IRP. The estimate provided to Ms. Jenner was in 2005 dollars and was without escalation and AFUDC. Pet. Ex, No. 4, pp. 13-15 (Moreland Direct). In addition to the Company's confidential estimate, Mr. Moreland also presented a range based on Electric Power Research Institute's ("EPRI") estimates in the amount of $1.6 to $2.1 billion for an IGCC Project similar to the Edwardsport IGCC Project. *Id.* at 13. On direct examination at the hearing, Mr. Moreland explained that the cost estimate information for the IGCC Project set forth in his direct testimony had been superseded by the cost estimate resulting from the FEED Study.

Mr. Moreland further testified that the Company has identified rapidly escalating costs of certain commodities, such as steel and concrete, along with escalating labor rates. According to Mr. Moreland, such increases are not unique to the IGCC Project and would have a corresponding impact on baseload alternatives. *Id.* at 14-15. In furtherance of this point, Mr. Moreland sponsored supplemental testimony regarding updated estimated costs for other candidate supply-side technology options, including supercritical pulverized coal units, natural gas-fired simple cycle combustion turbine units, natural gas-fired combined cycle units, and new wind power projects. Mr. Moreland stated that he believes that any analysis of the high end of the Company's Edwardsport Project cost estimate range should be compared to alternatives in a manner that appropriately reflect the recent escalation in construction costs for any potential alternative projects. Pet. Ex. No. 14 (Moreland Supplemental).

In her direct testimony, Ms. Pashos explained that there is an estimated 10 to 20% capital cost differential between an IGCC plant and pulverized coal plant. As a result, the Company has aggressively sought local, state and federal tax incentives in an effort to reduce the cost of the Project. Ms. Pashos explained the basis for the state and local tax incentives and indicated that based on a project cost of $1.985 billion, tax incentives will total about $316.5 million. Pet. Ex. No. 2, pp. 11-16 (Pashos Direct); Pet. Ex. No. 17, p. 19 (Pashos Rebuttal). In her amended supplemental testimony, Ms. Pashos reported that the Company received an award of $133.5

million in federal investment tax credits which will accrue to the benefit of the Company's native load customers." Pet. Ex. No. 16, p. 2 (Pashos Supplemental).

The FEED Study Report, sponsored by Mr. Zupan in his rebuttal testimony, sets forth the Company's updated cost estimate of $1.985 billion for the IGCC Project, including future escalation of 4% per year.[13] Pet. Ex. No. 20-A and Pet. Ex. No. 20-B Confidential and 20-C Confidential. Mr. Zupan conceded that this capital cost estimate is about 5.2% higher than the high end of the range included in Mr. Moreland's direct testimony, but is within the range of the $1.6 to $2.1 billion EPRI-based estimate included in Mr. Moreland's direct testimony. The FEED Study Report includes an explanation as to how Bechtel used detailed engineering drawings in estimating costs. The estimate is also based on GE prices for equipment it will manufacture or directly procure, as well as pricing information from other vendors. The estimate includes all purchase, supply and construction costs for the Project, including transmission costs associated with the Project, through the assumed commercial operation date in late 2011. Pet. Ex. No. 20-A.

The FEED Study cost estimate assumes that there will not be a lump sum turnkey contract with GE/Bechtel for construction of the entire Project. The Company concluded that such an approach would be too expensive as costs would be added by GE/Bechtel to cover contingencies which may never occur. Rather, consistent with the contracting approach taken by the Company on pollution control construction projects of over $1 billion currently in progress or completed in recent years, the Company will assume greater control over construction of the Project in an effort to gain greater cost savings. *Id.*

The FEED Study cost estimate of $1.985 billion does not take into consideration the effect of federal, state and local tax incentives awarded to the Company or for which the Company is eligible, which Ms. Pashos said in her rebuttal testimony is estimated to exceed $450 million. Pet. Ex. No. 17, p. 19 (Pashos Rebuttal). On cross examination at the hearing, Mr. Rose testified that the net present value of the tax incentives would be approximately $230 per kW of capacity for the IGCC plant.

With respect to interconnection and the corresponding additional costs associated with the IGCC Project, Mr. Snead submitted testimony regarding the transmission facilities required to connect the Edwardsport IGCC Project. Mr. Snead stated that since the Midwest ISO has assumed responsibility for evaluation of new generator interconnections to the transmission system the Company must submit an interconnection request. Mr. Snead said Duke Energy Indiana submitted this request in June, 2004 for the Midwest ISO to begin evaluating the impact of a 600 megawatt IGCC facility at the Edwardsport site. He testified that the interconnection feasibility study indicated that the proposed IGCC project could be accommodated at the Edwardsport site, but that certain facilities may need to be upgraded. The original Midwest ISO studies indicate that the approximate cost for interconnecting the proposed facility to the transmission system would be $7.2 million - approximately $5.7 million for a new substation and approximately $1.5 million for relocating some transmission facilities. Mr. Snead testified that the Midwest ISO estimates were reasonable and that the studies will continue to be updated as

[13] In his rebuttal testimony, Mr. Rose said that ICF used a general inflation rate of 2.25% for escalation of capital costs for new generation plant costs. Accordingly, he indicated that the Company's use of a 4% escalation rate built conservativeness into the Company's estimate because if ICF's escalation forecast is correct then actual IGCC Project costs will be less than projected. Pet. Ex. No. 25, p.10 (Rose Rebuttal).

the design of the IGCC project becomes finalized. Pet. Ex. No. 9, p. 8 (Snead Direct). At the Evidentiary Hearing Mr. Snead indicated that the deliverability study determined that the potential costs of transmission upgrades are approximately $20 million in a worst case scenario.

2. **OUCC and Intervenors' Evidence and Petitioner's Response.** IIG witness Mr. Nicholas Phillips stated that the IGCC Project's cost is estimated to be $3,142/kW, which is significantly higher than either a conventional pulverized coal or a nuclear unit. Mr. Phillips explained that the Petitioner is relying on local, state and federal incentives to make the IGCC Project an economical choice compared to a pulverized coal unit. Mr. Phillips also noted that Duke Energy Indiana did not prepare detailed cost estimates for carbon capture and sequestration in this proceeding. IIG Ex. 1, pp. 3-4. In his testimony Mr. Phillips proposed that the construction costs be capped at the latest estimate of $1.985 billion as an incentive to the Company to efficiently manage construction costs. According to Mr. Phillips, this is especially important in light of the Company's latest cost revision, which represents a 5.2% increase over the Company's prior high-end forecast. *Id.* at 11-12. Mr. Phillips also testified that a Duke witness in a proceeding before the North Carolina commission stated, in a portion of his testimony, that IGCC technology is "complex and finicky," not the right technology to meet Duke's needs at this time, and not a viable option at present. *Id.* at 5-7.

In his testimony CAC witness Mr. Schlissel quoted the FEED Study Report which indicates that the new cost estimate "assumes that it will not be necessary to pay significant premiums to attract craft labor for the Project, assuming 40 hour work weeks with only occasional overtime." Relying on testimony with respect to a plant in Minnesota, Mr. Schlissel opined that, given the demand for skilled labor, the Company's failure to recognize a requirement for labor premiums reflects that the Company is underestimating the cost of constructing the IGCC Project. He also pointed to testimony from Mr. Rose that new coal-fired capital costs have increased approximately 90% to 100% since 2002 due to competition for the resources needed to construct new power plants. According to Mr. Schlissel, this competition makes it reasonable to assume that the IGCC Project will experience additional cost increases before it is completed. Mr. Schlissel indicated that he believes that it is imprudent for the Company to pursue a new power plant without considering the potential for higher capital costs. RC Ex. E, pp. 30-35.

In his rebuttal testimony Mr. Roebel testified that the $1.985 billion cost estimate for the IGCC Project contained in the FEED Study is reasonable. He further stated that with the completion of the FEED Study, the Company has a significant amount of detailed knowledge about the project, more knowledge than normal for this stage of a major project. He also said that Bechtel was able to perform take offs from engineering drawings, a much more accurate method for estimating quantities. Further, Bechtel was able to obtain current pricing for over 90% of the bulk quantity materials and equipment from vendors. Mr. Roebel noted that the estimate was rigorous and performed by seasoned personnel using accepted estimating techniques. Pet. Ex. No. 27, p. 2 (Roebel Rebuttal).

Mr. Roebel rejected Mr. Schlissel's concerns regarding Duke Energy Indiana's assumption that it would not have to pay significant overtime premiums to attract labor for the Project. Mr. Roebel stated that the Company has constructed (or is in the process of constructing) well over $1 billion of pollution control equipment on its generating stations in the same general area as the Edwardsport IGCC Project, and frequently meets with local contractors and local unions. Local union officials have indicated that they welcome the IGCC Project as a long term local project without significant travel. *Id.* at 3.

Mr. Roebel also responded to Mr. Phillips' and Mr. Schlissel's concerns regarding whether the Company made reasonable assumptions with respect to escalating commodity costs. Mr. Roebel stated that the Company's cost estimate is based on very recent quotes and estimates from vendors and suppliers (as recent as March 2007), and the Company has included a 4% escalation rate in the estimate. Further, he stated that if commodity prices do begin rapidly escalating beyond the Company's control, such forces would have a similar impact on competing technologies. *Id.*

At the hearing on cross examination Mr. Roebel, while affirming his conclusion that the Company's updated cost estimate is reasonable, noted there could be circumstances beyond the Company's control that could cause the cost of the IGCC Project to increase. Because of such a possibility, he said it would be unfair for the Commission to place a cap of $1.985 billion in capital costs that the Company could recover from its customers through rates. Likewise, Ms. Pashos testified in her rebuttal testimony and at the hearing that due to the potential for circumstances beyond its control, the Company would not agree to forego its rights under the Indiana certificate of need statutes by agreeing to an absolute cost cap for purposes of IGCC Project cost recovery. Pet. Ex. No. 17, pp. 11-12 (Pashos Rebuttal).

3. Commission Discussion and Findings Regarding the IGCC Cost Estimate. The Company's $1.985 billion cost estimate for the IGCC Project is the result of engineering and technical work on the Project encompassed within the FEED Study Report, which was undertaken and completed over a period of 18 months. In addition, GE, Bechtel, and the Company undertook numerous site specific studies and activities which are summarized in the FEED Study Report. The detailed engineering drawings produced as part of the FEED Study provide significant detail about the IGCC Project. Based on this information, Bechtel estimated the quantities and costs of many commodities. GE provided estimates for the equipment that it will manufacture or procure and other vendors provided estimates based on specifications for the equipment to be supplied. The estimate includes all purchase, supply and construction costs for the IGCC Project, based on a commercial operation date in late 2011. Although the various components of the estimate are not fixed, as supply or construction contracts have not been concluded, the cost estimate is based on component estimates from March 2007 which include an escalation rate of 4%. In addition, the Company's FEED Study cost estimate is within the range of the EPRI based cost estimate ($1.6 to $2.1 billion) for an IGCC plant.

In considering the issues in this Cause we find that the Company adequately considered the possibility of labor premiums and overtime. In recent years the Company has been and remains involved in a number of major pollution control construction projects. Mr. Roebel testified that the Company regularly meets with local contractors and labor unions which welcome the prospect of working on a major project relatively close to home. Mr. Roebel said he was comfortable with the Company's assumptions on labor rates and we find that the Company's approach on this issue is reasonable for purposes of this proceeding.

We also find that the Company's proposed contracting approach, whereby it will actively manage the project, is reasonable based on the facts presented in this matter. A lump sum turn key approach with one primary contractor or contractors taking on price and other risks necessarily means that the contractor will build large contingency amounts into the contract to ensure it will cover all possible costs and make a profit. Although such an approach could (assuming the contract is truly all encompassing and provides a fixed price) provide greater certainty of costs to the owner, it could also increase the total project cost.

With respect to the proposal presented in this matter to formally cap the cost of the IGCC Project, we note that our consideration in this proceeding is expressly limited to the Company's $1.985 billion cost estimate presented in this Cause. While the provisions set forth in the IC 8-1-8.8-12 outline specific cost recovery incentives that may be awarded, up to the Commission approved cost, the statute does not provide for or contemplate the open-ended approval of tracking incentives for additional costs that may be incurred by the Company. The Commission recognizes that the cost tracking mechanism set forth in IC 8-1-8.8-12 provides a powerful financial incentive that allows for the timely recovery of project costs from ratepayers prior to completion of the project without placing shareholder dollars at risk. However, in order to receive approval for this statutory cost tracking incentive it is incumbent upon the Petitioner to provide substantial documentation that the expected costs associated with qualified utility system property and the schedule for incurring those costs is reasonable and necessary. IC 8-1-8.8-12(d).

The Commission finds that such a demonstration has been provided by the Company with respect to its $1.985 billion cost estimate for the IGCC Project in this proceeding. In reaching this determination the Commission notes the very high level of confidence the Company has in the final estimated cost of $1.985 billion. Several Company witnesses expressed the belief that the estimate was very accurate. Mr. Roebel testified that the $1.985 billion estimate was reasonable, was based on information as recent as March 2007 and even included a 4% escalation rate. He noted it was based on the FEED Study which provided more detailed knowledge than the Company would typically have at this stage of a major project. He noted that Bechtel performed take offs which produce much more accurate estimates of quantities that will be needed. Also, Bechtel obtained actual current pricing for 90% of the bulk quantities and equipment. Mr. Roebel stated that these factors made the Company very confident in the $1.985 billion dollar estimate. Again, Mr. Roebel's confidence was shared by several Company witnesses.

In reaching this conclusion and approving the $1.985 billion cost estimate for the IGCC Project in this proceeding, the Commission recognizes that certain parties have predicted that costs of the IGCC Project will rise and that a cost-cap is therefore necessary. In analyzing the cost-cap issue, the Commission finds that of central importance to our consideration of this issue is an initial examination of our ability to monitor the IGCC Project and act in a manner that would allow us to effectively review cost issues in event of future increases.

As outlined previously in this Order, the Commission has an obligation to generally review the continuing need for the clean coal technology system under construction under IC 8-1-8.7-5, and shall at the request of the public utility maintain an ongoing review of the construction as it proceeds pursuant to IC 8-1-8.7-7. Under this provision, the Commission must hold a public hearing before it may approve or deny a proposed increase in the cost estimates for the implementation, construction, or use of clean coal technology. As the Petitioner has requested ongoing review in this proceeding, in the event that the cost of the IGCC Project increases, the Company must demonstrate that such increased costs are warranted. Absent such a demonstration, the Commission may appropriately deny incentive tracking treatment for any additional costs under IC 8-1-8.8-12. This tool, if utilized by the Commission to deny a request for incentive tracking of additional costs would, in the near term, act to effectively shift the financial risk for the additional costs from ratepayers to shareholders.

In addition, and aside from the financial incentive issues discussed herein, pursuant to IC 8-1-8.7-5, the Commission retains the general authority to modify or revoke the certificate granted in this Cause if it subsequently finds that implementation of the technology will not serve the public convenience and necessity. Of central importance to our continuing oversight of the IGCC Project is an ongoing examination of technical and cost related issues as, despite possible action by the Commission under IC 8-1-8.7-5 to modify or revoke the certificate, recovery of approved costs from ratepayers is assured under the provisions set forth in IC 8-1-8.7-6. Under this provision, if a public utility cancels the implementation of the technology as a result of the modification or revocation of a certificate by the Commission under IC 8-1-8.7-5, the public utility may recover the amount of its investment in the technology, along with a reasonable return on the unamortized balance.

The foregoing statutory framework specifically allows the Commission to: generally review additional costs prior to acting on a request for the award of additional incentives; monitor ongoing compliance with any incentives awarded; and, revoke *any incentive* approved in this order, pursuant to IC 8-1-8.8-15, if the Commission finds that the project no longer complies with the provisions of the Order concerning the incentive. This express and ongoing statutory authority argues against the need for the Commission to impose a cost-cap in this proceeding. We therefore decline to take such action in this Cause.

For the reasons discussed herein, we find the Company's $1.985 billion cost estimate to be reasonable and find that is the best estimate of construction costs based on the evidence of record. In addition, we hereby approve the Company's request of ongoing review of the IGCC Project. Duke Energy Indiana is directed to file an ongoing review update, including any updates to the project cost estimate and the project schedule contemporaneous with its semi-annual IGCC Rider filings. [14]

D. IGCC Technology Reliability.

1. Intervenors' Evidence and Petitioner's and Intervenors' Response Regarding Reliability of IGCC Technology. IIG witness Mr. Phillips expressed concern about the reliability of the proposed IGCC plant. His concerns were based on his review of testimony and filings at various other state utility commissions regarding IGCCs and the time it took for two demonstration IGCC projects to reach higher capacity factors.

Mr. Phillips recommended that the Commission require the Edwardsport IGCC Project to operate at a minimum 82% capacity factor as this is the factor at which Mr. Phillips contends the IGCC Project will most economically meet customers' demands. Mr. Phillips also indicated that he believes that ratepayers must be protected from management's decision to construct a plant using technology that has historically demonstrated lower reliability than plants that utilize

[14] Pursuant to IC 8-1-8.8-13, an eligible business shall file a monthly report with the lieutenant governor stating: (1) The amount of Illinois Basin coal, if any, purchased during the previous month for use in a new energy generating or coal gasification facility; (2) The amount of any fuel produced by a coal gasification facility and purchased by the eligible business during the previous month; (3) Any other information the lieutenant governor may reasonably require. We find that such filings would assist the Commission in its oversight role and shall also be made in this Cause as a condition of this Order.

pulverized coal. IIG Ex. 1, p. 13 (Phillips Direct). Mr. Phillips indicated that Consumers Energy in Michigan recently expressed concern regarding IGCC technology in the context of its application for approval of its "Balanced Energy Initiative." He further testified that Consumers Energy presented testimony that "implementing IGCC at this time represents both reliability and cost risks to customers without the substantial benefit of improved technical or emissions performance." According to Mr. Phillips, such testimony indicated that further research was needed to demonstrate IGCC's effectiveness with carbon capture and sequestration. *Id.* at 7-8.

In response to Mr. Phillips' concern, IWF/CATF witness Mr. Douglas Cortez presented testimony that early IGCC demonstration plants, built over 10 years ago, experienced startup problems and required several years to achieve high levels of reliability. However, he said it is a mistake to interpret this experience as proof that IGCC is not a reliable technology. According to Mr. Cortez, a recent study by Higman *et al.* examined the history of IGCC plants in the U.S. and Europe and found that the source of unreliability in some IGCC plants is in areas outside the gasification and gas process sections of the plant. As such, the reasons for reliability issues are well understood and are unlikely to occur in new IGCC plants that can benefit from the lessons learned from earlier plants. Mr. Cortez testified that IGCC plants have demonstrated high levels of reliability comparable to conventional coal plants and that, as the IGCC technology has completed its pioneer plant stage, he anticipates that the next generation of IGCC plants will perform reliably. CATF/IWF Ex. 2, pp. 1-2 (Cortez Rebuttal).

In response to Mr. Phillips' statement that other utilities have concerns regarding construction of IGCC plants, Mr. Cortez stated that the utility industry is becoming more accepting of IGCC technology and several utilities are aggressively pursuing IGCC projects as the preferred option for clean coal powered generation. According to Mr. Cortez, in November 2006 the DOE and IRS announced winners of about $1 billion in gasification tax credits which were awarded to a select number of the 45 projects that were initially bid. The winners included Duke Energy Indiana, Southern Company and TECO Energy. Mr. Cortez stated that Mr. Phillips' testimony paints a picture of utility rejection of IGCC, whereas, in fact, the industry is moving toward IGCC technology as a viable alternative to address the environmental problems that plague conventional coal plant technology. *Id.* at 3.

Mr. Moreland similarly rejected Mr. Phillips' concerns regarding the reliability of the Edwardsport IGCC Project, stating that he was not surprised that it took some time for the two IGCC demonstration plants, the Polk plant and the Wabash River Repowering Project, to reach higher levels of availability. Both plants were part of the U.S. Department of Energy's clean coal program and were required to test a variety of fuels and perform other tasks which impacted availability. Mr. Moreland testified that the industry expected to, and has, learned from these projects. With respect to the Wabash River Repowering Project, additional issues arose out of the split ownership between the gasification island (owned by Destec and its successors) and the power generation island (owned by Duke Energy Indiana). This will not be an issue for the Edwardsport Project because GE is designing both the gasification island and the power generation island. Further, the Company will be operating both parts of the IGCC Project which will also address issues faced by the Wabash River Repowering Project. Pet. Ex. No. 19, pp. 3-5 (Moreland Rebuttal).

Mr. Moreland affirmed his belief that the IGCC Project will be very reliable, based, in part, on the significant lessons learned from the IGCC demonstration projects. He also noted that GE has a large database of best practices for gasification design that it has developed based on information from technology licensees. *Id.* at 4-5. At the hearing on cross examination, Mr. Moreland testified that he believes that the reliability of an IGCC plant and a new supercritical pulverized coal plant would be similar over time. Mr. Moreland also indicated that the overall equivalent availability between supercritical pulverized coal and IGCC plants would be similar.

Mr. Roebel also presented testimony in response to Mr. Phillips' contention that IGCC technology is unproven. Mr. Roebel's view is that IGCC technology involves a merger of two mature technologies: coal gasification, which, as described by Dr. Shilling, has been practiced for many years; and combined cycle generating plants, which are operating on natural gas throughout the country. Mr. Roebel noted that the industry now has a very good experience base with two operating demonstration IGCC plants, including the Wabash River Repowering Project, with which the Company now has over 10 years of experience operating the combined cycle power plant in conjunction with the gasification plant. Further, subject to stringent confidentiality limitations, the Edwardsport IGCC Project team has had unprecedented access to GE's design effort and has observed how GE has incorporated lessons learned from prior IGCC projects. Though he said it would not surprise him if the Company needs to make some modifications early in the operating life of the IGCC Project, as this would not be unusual for any new large power plant, Mr. Roebel stated his opinion that the Edwardsport IGCC Project will be reliable, and will serve the Company's customers well. Pet. Ex. No. 27, p. 4 (Roebel Rebuttal).

Ms. Jenner testified that Mr. Phillips mischaracterized her testimony when he stated that an 82% capacity factor is the capacity factor that the Petitioner determined would most economically meet customers' demands. In fact, according to Ms. Jenner, Duke Energy Indiana had not done any STRATEGIST® model runs to determine the capacity factor at which the IGCC Project must run to be the least cost option. Ms. Jenner testified that the model runs show the plant running at 82%, not that 82% capacity *is required for* the IGCC Project to be a least cost option. Pet. Ex. No. 24, p. 14 (Jenner Rebuttal). In addition, Mr. Moreland testified that Mr. Philips' proposed minimum capacity factor requirement fails to recognize that the Edwardsport IGCC Project, just like any other generating plant, will require periodic maintenance outages for such things as turbine overhauls. While Mr. Moreland does not anticipate operating problems, he pointed out that the Commission has ample authority to investigate issues and craft appropriate remedies if large operating problems do occur in the future. Pet. Ex. No. 19, p. 4 (Moreland Direct).

2. Commission Discussion and Findings on IGCC Project Reliability. The testimony presented on this issue demonstrates that the Company has over 10 years of experience with the Wabash River Repowering Project; has studied IGCC technology; and, has worked closely with GE/Bechtel in the adaptation of the GE IGCC reference plant for purposes of the IGCC Project. The record in this case establishes that based on this background and analysis, the Company has concluded that an IGCC plant is technically feasible and commercially reasonable.

Based on the evidence presented in this Cause, we find that the IGCC Project is technically feasible and commercially reasonable and is expected to be a reliable baseload generating station. The contention that an 82% capacity factor is the minimum capacity factor needed to make the plant commercially reasonable was effectively rebutted and there is no statutory basis for limiting the Company's rate recovery based on the plant achieving a certain minimum capacity factor. For the foregoing reasons, we decline to place a capacity factor limit or goal on the Edwardsport IGCC Project.

E. Environmental Impacts of the Proposed IGCC Project.

1. Overview of Historic, Current, and Potential Emissions Reduction Requirements. Duke Energy Indiana presented evidence that electric utilities are likely to face continuing emission reduction requirements. The 1990 Clean Air Amendments required Duke Energy Indiana to reduce SO_2 emissions by 50% and NO_x emissions by 25%. As stated in Mr. Stowell's testimony, the Petitioner complied with these regulations at a cost of over $540 million in capital. The United States Environmental Protection Agency ("EPA") and the State of Indiana's NO_x State Implementation Plan required an additional 50% reduction in summertime NO_x emissions by May 2004. The Petitioner complied with these requirements at a cost of nearly $600 million in capital. Pet. Ex. No. 7, pp. 4-8 (Stowell Direct).

Additional environmental restrictions have been recently imposed under the new CAIR and CAMR rules. Mr. Stowell stated that the CAIR mandates further reductions in SO_2 and NO_x emissions and the CAMR requires electric utilities to permanently cap and reduce mercury emissions from coal-fired power plants and meet specific New Source Performance Standards. *Id.* As Mr. James Rogers discussed, compliance with CAIR/CAMR requires investment in capital of over $1 billion (Duke Energy Indiana received approval from this Commission for its first phase CAIR/CAMR compliance plan in consolidated Cause Nos. 42622 and 42718 (*Ind. Util. Reg. Comm'n*, May 24, 2006)). Pet. Ex. No. 1, p. 8 (Rogers Direct). The Petitioner anticipates that additional SO_2, NO_x, and mercury requirements could be enacted in the future. *Id.* at 8-9, 12-15.

In addition, the Petitioner, the OUCC, CAC, and CATF/IWF expressed consensus that carbon regulation is all but certain at some point in the future. Various witnesses from all parties discussed the details of potential carbon regulations and recent Congressional bills proposing carbon regulations, including proposals by Senators McCain, Lieberman, Kerry, and Bingaman. Additionally, Petitioner's witness Mr. Rogers testified that nine northeastern states had formed the Regional Greenhouse Gas Initiative to develop a regional cap-and-trade plan for CO_2 emissions. Mr. Rogers also presented testimony regarding California's September 2006 AB 32, the nation's first bill to reduce greenhouse gas emissions. According to Mr. Rogers, this bill could signify forthcoming regulatory changes on the national level as California has historically been a leader in environmental regulations. *Id.* at 16-17.

2. The IGCC Project Environmental Footprint Relative to Current Emission Mandates. The Petitioner presented testimony in which it indicated that the IGCC Project will, in many respects, have a relatively smaller environmental impact than other types of coal-fired plants. Petitioner's witness Mr. Moreland testified that the existing 160 MW Edwardsport plant runs less than 30% of the time and emits approximately 11,000 tons of SO_2, NO_x, and particulates in an average year. Conversely, the 630 MW IGCC Project, running 100% of the time, would emit about 2,200 tons of these pollutants annually. Pet. Ex. No. 4, p. 10 (Moreland Direct). Mr. Moreland further testified that the IGCC Project will provide 90% mercury capture independent of coal type at a fraction of the cost of a pulverized coal plant. Mr. Moreland presented testimony that the IGCC Project will be capable of SO_2 removal to a level of 0.014 lb/MMBtu (approximately 99.7% removal); removal of NO_x emissions to a level of 0.06

lb/MMBtu; and, the removal of particulate emissions to a level of 0.007 lb/MMBtu. According to Mr. Moreland, all of these levels exceed limits set by the New Source Performance Standards. Pet. Ex. No. 4, pp. 10-11 (Moreland Direct).

In addition, Mr. Rogers testified that the IGCC Project will use approximately 30% less water and generate 50% less solid waste than a conventional pulverized coal plant, and that the 99% pure elemental sulfur and slag generated by the plant are salable by-products. Based on this overview, it is Mr. Rogers' belief that with the IGCC Project, Duke Energy Indiana will be able to substantially increase its baseload capacity while simultaneously reducing its environmental footprint. Pet. Ex. No. 1, pp. 6-7 (Rogers Direct). While IGCC technology is capable of reducing NO_x emissions to limits established by New Source Performance Standards, Mr. Rogers testified that Duke Energy Indiana has committed to installing Selective Catalytic Reduction units that will make the Project the cleanest IGCC plant in the nation, with NO_x emissions of 0.02 lb/MMBtu. *Id.* at 7; Pet. Ex. No. 4, p. 11 (Moreland Direct). Petitioner further maintained that construction of the IGCC Project lessens the likelihood that it will need to install expensive retrofit environmental compliance equipment, even if future, stricter reductions are mandated.

CAC Witness Grant Smith testified that although the IGCC technology will reduce some emissions, it will increase others because it will be operating much more frequently than the existing Edwardsport plant. For example, Mr. Smith opined that lead emissions will increase by 14,555%, carbon dioxide emissions will increase by 785%, carbon monoxide emissions will increase by 1,480%, particulate matter emissions will increase by 297%, and volatile organic compounds emissions will increase by 678%. CAC Ex. A. p. 8. (Grant Smith Direct).

Intervenors' CATF/IWF witness Mr. Thompson testified that the Edwardsport IGCC Project proposed by the Company will have superior environmental performance relative to coal plants across the nation and even around the world. He stated that SO_2 and NO_x emissions from the plant would be much lower than proposals for pulverized coal plants around the nation. Further, Mr. Thompson stated that the IGCC Project could perform at levels better than the manufacturer's guarantee, and that it could achieve 98% mercury removal or higher. On cross examination at the hearing, Mr. Thompson also testified that the rate of emissions per MWh for all pollutants would be less for the Edwardsport IGCC Project than for pulverized coal, including lead, CO, and VOCs. CATF/IWF Ex. 3, pp. 5-7 (Thompson Direct).

OUCC witness Ms. Smith testified that the combined reduction of SO_2, NO_x, mercury and particulate matter that will be achieved by the new Edwardsport IGCC Project, when compared to levels currently emitted from the existing Edwardsport plant, is significant considering that the proposed plant's capacity is far greater than the existing plant. Public's Ex. 2, p. 4 (Smith Direct).

3. The IGCC Project's Thermal Efficiency. According to the testimony of Mr. Rogers, IGCC plants are capable of achieving superior thermal efficiencies due to the combined cycle configuration. Pet. Ex. No. 1, pp. 7 (Rogers Direct). Mr. Roebel testified that the IGCC Project is a state-of-the-art, highly efficient generating station. Pet. Ex. No. 12, p. 6 (Roebel Direct). Mr. Rose testified that as a result of its efficiency the IGCC Project will utilize less coal per MWh and produce less CO_2 and other emissions than competing coal technologies. Pet. Ex. No. 6, pp. 47 (Rose Direct). According to the Petitioner's witness Ms. Jenner, the Company's modeling runs demonstrate that the IGCC Project should consistently be among the first units economically committed and dispatched on the Duke Energy Indiana system, due to its efficient heat rate and low environmental emissions. Pet. Ex. No. 5, p. 25 (Jenner Direct).

F. Tax and Economic Benefits and Local Support for the IGCC Project. Petitioner's witness Ms. Pashos testified that the Indiana legislature has demonstrated support for funding of clean coal technology projects through investment tax credits, as evidenced by IC 6-3.1-29. Ms. Pashos stated that local support in Knox County is very high, with the Knox County Council unanimously approving a ten-year real and personal property tax abatement and a tax increment finance district. According to Ms. Pashos, the ten-year real and personal property tax abatement represents the maximum allowed by law. Ms. Pashos further represented that under the Clean Coal Facilities Investment of the Energy Policy Act of 2005, the IGCC Project has received the maximum amount of $133.5 million in federal tax credits, demonstrating support for this type of clean coal technology at the national level. According to Ms. Pashos, Duke Energy Indiana will receive a total of approximately $450 Million in tax incentives. Pet. Ex. No. 2, pp. 16-18 (Pashos Direct); Pet. Ex. No. 17, p. 19 (Pashos Rebuttal).

In her testimony Ms. Soller addressed why she believes that the IGCC Project is attractive for Indiana. Citing the testimony of Petitioner's witness Mr. Rogers in the North Carolina case NC Docket E-7, sub 790, Ms. Soller's testimony presents that there is strong local and state support for an IGCC facility to promote Indiana's coal industry. Public's Ex. 1, p. 17 (Soller Direct).

1. Economic Benefits of the IGCC Project. Petitioner's witness Ms. Pashos presented testimony regarding the Economic Impact Study performed by Ernst and Young which confirmed that the construction of the IGCC Project would have a significant positive impact on both the local and statewide economy. According to Ms. Pashos, the IGCC Project will involve a total investment of almost $2 billion, creating an increased tax base for both state and local government. Ms. Pashos stated that the IGCC Project will use about 1.5 million tons of locally mined Indiana coal per year, at a cost of $45-50 million annually. Ms. Pashos further explained that the construction of the IGCC Project will result in large increases in the amount of state and local taxes paid as it will, upon completion, result in the creation of 50 permanent new jobs. The majority of these jobs will be high-skilled and high-paying, with an estimated payroll of $4-5 million. In addition, construction of the project will result in the creation of approximately 800-900 construction jobs during the three year construction period. During peak construction the number of jobs will increase to nearly 2,000. Ms. Pashos testified that she believes that, as the IGCC Project will be among the first of its size in the United States, the technological innovation and leadership in clean coal technology represented by the IGCC Project will reflect positively on the State of Indiana. Pet. Ex. No. 2, pp. 12, 16-18 (Pashos Direct).

Mr. Noland testified in support of the IGCC Project and indicated that the plant will use Indiana's abundant coal reserves in a more environmentally friendly manner than competing technologies. Mr. Noland testified that currently over half of coal consumed in Indiana comes from outside the state. As the IGCC Project is designed to run on Indiana coal, it will create additional direct mining jobs in Indiana. Mr. Noland further noted that for every new direct mining job, approximately 3.5 additional jobs will be created and supported in the surrounding area. Additionally, Mr. Noland testified that a project of this scope indirectly spurs the local economy. According to Mr. Noland, during construction, increased supplier and consumer purchases could create almost 2,000 additional jobs with a corresponding $186 million in additional personal income. ICC Ex. JNN, pp. 1-10 (Noland Direct).

2. **The IGCC Project and the State Energy Plan.** Ms. Pashos testified that the IGCC Project is consistent with Indiana's recently unveiled Strategic Energy Plan ("Energy Plan") and the State Utility Forecasting Group's analysis of Indiana's capacity needs. Ms. Pashos characterized the IGCC Project's use of Indiana coal, in combination with clean coal technology to produce cost-effective electricity while providing jobs and increased capital investment in the state, as a prime example of a "homegrown" energy resource. Pet. Ex. No. 2, p. 18 (Pashos Direct).

ICC witness Mr. Noland also discussed the Energy Plan, noting that it specifically advocates the use of IGCC technology to allow for the utilization of Indiana's coal reserves and reduce reliance on imported coal. Mr. Noland indicated that the IGCC Project will meet the goals outlined in the Energy Plan as it will produce energy from Indiana's natural resources utilizing clean coal technology, a central component of the Energy Plan. ICC. Ex. JNN, p. 4 (Noland).

10. <u>Ultimate Findings Regarding Reasonableness and Necessity for Construction of Edwardsport IGCC Project</u>. The testimony and evidence presented in this matter demonstrates that the IGCC Project will result in relative environmental benefits compared to conventional pulverized coal technology. The IGCC Project will provide 90% mercury capture independent of coal type at a fraction of the cost of a pulverized coal plant; will be capable of SO_2 removal to a level of 0.014 lb/MMBtu; removal of NO_x emissions to a level of 0.06 lb/MMBtu; and, the removal of particulate emissions to a level of 0.007 lb/MMBtu. While all of these levels exceed limits set by the New Source Performance Standards, Duke Energy Indiana has also committed to install SCRs to further reduce emissions from the plant.

The IGCC Project presents additional relative benefits to the environment as it will utilize approximately 30% less water and generate 50% less solid waste than a conventional pulverized coal plant, while removing elemental sulfur at the pre-combustion stage, creating a salable by-product. It is also noteworthy that the while the existing 160 MW Edwardsport plant runs less than 30% of the time and emits approximately 11,000 tons of SO_2, NO_x, and particulates in an average year, if the 630 MW IGCC Project were to run 100% of the time, it would emit about 2,200 tons of these pollutants annually. The fact that this dramatic reduction in emissions can be accomplished while increasing generation capacity in the state is a direct result of the advanced technology utilized by the IGCC Project.

Based on the foregoing, we find that the IGCC facility utilizing SCRs satisfies the criteria as clean coal technology and should present tangible environmental benefits to the state of Indiana with respect to compliance with current environmental air quality standards, while providing the foundation for cost effective compliance with possible future environmental mandates. In addition, the testimony presented in this matter demonstrates that IGCC technology offers superior thermal efficiency, which will contribute to lower variable costs and can meet Petitioner's future baseload capacity requirements using Indiana coal as a fuel supply.

The Commission further finds that planning for the likelihood of more stringent emission reductions and the possibility of carbon regulation is a reasonable and prudent aspect of the Petitioner's planning process. While there is a degree of uncertainty regarding the scope and cost of future carbon emissions reductions, the Commission recognizes that there is a strong possibility that carbon regulations will be forthcoming and that the IGCC Project could represent an initial step toward compliance with any future regulatory requirements.

In reaching these conclusions, the Commission also recognizes that the availability of substantial federal, state and local tax benefits for the IGCC Project offer additional support for the deployment of the IGCC Project. The Commission also finds that the IGCC Project will provide attendant benefits to the economy of the State of Indiana in the form of an increased number of jobs related to the construction and operation of the plant; an increased number of jobs in coal and related industries; and an increased number of jobs in the surrounding communities.

Based on all of the evidence presented regarding the need for the proposed Edwardsport IGCC Project, we conclude and find that the evidence presented in this matter demonstrates that the Petitioner has a need for additional baseload capacity over the next few years in order to reliably meet its customers' increasing electricity requirements.

We have indicated in previous CPCN cases that "least-cost planning is an essential component of our Certificate of Need law."[15] We have defined "least-cost planning" as a "planning approach which will find the set of options most likely to provide utility services at the lowest cost once appropriate service and reliability levels are determined." *Id.* However, we have emphasized that the CPCN statute does not require the utility to automatically select the least cost alternative. Nor does the statute require the utility to ignore its obligation to provide reliable service or to disregard its exercise of reasonable judgment as to how best to meet its obligation to serve. "If an Indiana utility reasonably considers and evaluates the statutorily required options for providing reliable, efficient, and economic service, then the utility should, in recognition that it bears the service obligations of Ind. Code § 8-1-2-4, be given some discretion to exercise its reasonable judgment in selecting the option or options to implement which minimize the cost of providing such service."[16]

In this proceeding, the Petitioner has demonstrated that it adequately considered alternative means of meeting its customers' demand requirements. The construction of the Edwardsport IGCC Project is consistent with Petitioner's integrated resource plan, and is consistent with the State's generation expansion plan. The construction of the Edwardsport IGCC Project is consistent with the State's energy plan and will provide other benefits to the State in terms of job creation. The Petitioner has sought to create and obtain tax credits for this Project for the benefit of its customers. Accordingly, we find that Petitioner should be granted certificates of public convenience and necessity and certificates of clean coal technology for this Project under both IC 8-1-8.5 and 8-1-8.7.

11. <u>Carbon Capture and Sequestration</u>.

A. Petitioner's Evidence. As described by Mr. Moreland, the IGCC Project is designed to be carbon-capture ready as the design utilizes a Selexol acid gas removal system

[15] *In re Petition of PSI Energy, Inc.*, Cause No. 42145, at p. 4 (*Ind. Util. Reg. Comm'n*, Dec. 19, 2002); *In re Petition of Southern Indiana Gas & Electric Co.*, Cause No. 38738, at p. 5 (IURC; Oct. 25, 1989).

[16] *In re Petition of PSI Energy, Inc.*, Cause No. 42145, at p. 4 (*Ind. Util. Reg. Comm'n*, Dec. 19, 2002); *In re Petition of PSI Energy, Inc.*, Cause No. 39175, at p. 14 (*Ind. Util. Reg. Comm'n*, May 13, 1992).

and the layout of the facility includes space for the inclusion of carbon capture equipment. As explained by Mr. Moreland, the smaller volume and concentrated nature of the gas stream make IGCC technology a very promising approach for future economic capture of CO_2. Pet. Ex. No. 4, pp. 11-12 (Moreland Direct). According to a study by the National Energy Technology Laboratory cited by Mr. Rogers in this testimony, it is estimated that outfitting an IGCC plant with carbon capture technology will result in an approximate 30% increase in plant electricity costs, as opposed to an estimated 68% cost increase to outfit a supercritical pulverized coal plant. Pet. Ex. No. 1, pp. 12-13 (Rogers Direct). In the event that carbon restrictions become a reality, this would result in cost savings for Duke Energy Indiana and its customers; but as Mr. Moreland cautions, there are corresponding capacity and efficiency penalties associated with the carbon capture process which require further study.

As Mr. Moreland points out, carbon capture is only the first step; once capture has been completed, sequestration of the removed CO_2 is also necessary. Working in conjunction with the Midwest Geological Sequestration Consortium, Duke Energy Indiana has conducted preliminarily studies regarding possible CO_2 sequestration at the Edwardsport site. According to Mr. Moreland, based on the results of the preliminary studies, there appears to be a good possibility that a significant amount of sequestration potential exists within an area below and immediately surrounding the site. Pet. Ex. No. 4, pp. 11-12 (Moreland Direct).

B. OUCC and Intervenors' Evidence and Petitioner's Response. Ms. Smith testified that the OUCC believes that it is in the economic interest of Indiana ratepayers to plan for carbon regulations, and that the IGCC Project addresses this interest. In her testimony, Ms. Smith acknowledged that Duke Energy Indiana has taken a leadership role with respect to research on this issue and that the Company is an active participant in the DOE's Midwest Regional Carbon Sequestration Partnership. Ms. Smith presented independent testimony showing that carbon capture and sequestration ("CCS") is estimated to be significantly less expensive for an IGCC plant than for a PC plant. Ms. Smith presented testimony that the OUCC was not aware of any major technical barriers regarding CCS, and that the design of the IGCC Project as proposed would allow for the capture of around 20% of the CO_2 without a significant impact on the current design or construction schedule. Ms. Smith testified that the OUCC supports building of the IGCC project with 20% carbon capture. Public's Ex. No. 2, pp. 9-14 (Smith Direct). On cross examination, Ms. Smith concurred that it made sense for the Company to further study carbon capture so as to fully understand the impacts to the plant.

Ms. Soller testified that IGCC with CSS must be explored if coal is to be part of Indiana's energy future, and that the construction of an IGCC plant provides the state with a unique opportunity to explore CCS. Ms. Soller also emphasized that the OUCC's support of the IGCC Project depended on the inclusion of partial CCS in the design and construction of the plant. Public's Ex. No. 1, pp. 6, 16, 19 (Soller).

The CATF and IWF also voiced support for the IGCC Project. Mr. Cortez testified that the IGCC technology can economically achieve very low emissions of regulated air pollutants such as SO_2, NO_x, and particulates. Mr. Cortez agreed with the Petitioner's description of the IGCC Project as "carbon capture ready." According to Mr. Cortez, the cost and performance penalties of carbon capture on a Supercritical Pulverized Coal plant ("SCPC") would be much greater than for IGCC, and that carbon capture technology is commercially unproven on a SCPC plant. Mr. Cortez testified that he believes that the cost and performance penalties of carbon capture in IGCC can be partially mitigated if the initial plant is designed for future retrofitting for carbon capture. Mr. Cortez also presented testimony as to additional equipment necessary for capturing and handling CO_2, including a CO_2 absorber; equipment to dehydrate the captured CO_2 and, equipment to compress the dehydrated CO_2 for handling and disposal. Mr. Cortez expressed the opinion that the detailed engineering of the added equipment could be carried out without delaying the construction schedule. CATF/IWF Ex. 1 pp. 6-13 (Cortez Direct).

CATF/IWF witness Mr. Melzer testified regarding the potential for sequestration near the IGCC Project and stated that he believes that enhanced oil recovery ("EOR") has great potential near the Edwardsport area. Mr. Melzer presented testimony that the Midwest Geologic Sequestration Consortium estimates potential for 860,000,000-1,300,000,000 barrels of oil while sequestering 140,000,000-440,000,000 tons of CO_2. CATF/IWF Ex. 6, pp. 10-13 (Melzer Direct).

CATF/IWF witness Mr. Thompson testified that the CATF and IWF strongly support the IGCC Project, but with the addition of the necessary work and equipment to capture and dispose of 15-20% of carbon emissions. Mr. Thompson believes that the IGCC Project offers significant environmental benefits and advantages while offering a valuable opportunity to investigate CCS. Mr. Thompson maintained that it is reasonable to expect mandatory regulatory constraints on carbon emissions for all power producers in the United States, and the IGCC Project represents an opportunity to "get ahead of the problem." Mr. Thompson views the IGCC Project as important for gaining experience in sequestering CO_2, and believes the Commission should require carbon capture as part of the CPCN. CATF/IWF Ex. 3, pp. 5, 9, 20-24 (Thompson Direct).

IIG Witness Mr. Phillips pointed out that there are currently no carbon regulations. Additionally, Mr. Phillips testified that carbon sequestration is commercially unproven, and expressed concern regarding the unknown capacity and efficiency penalties of adding carbon capture equipment to the IGCC Project. IIG Ex. No. 1, pp. 8-9 (Phillips Direct). In his cross-answering testimony addressed at the OUCC and CATF/IWF's support of CCS, Mr. Phillips stated that the current uncertainty of the economic impact of adding CCS to the plant makes it impossible for the Commission to determine whether the IGCC plant with CCS would be an economic means of meeting Duke Energy Indiana's ratepayers' needs. Mr. Phillips further testified that the Petitioner is still evaluating the technical feasibility of geologic sequestration, and pointed out that the environmental effects, legal liabilities, and costs of sequestration have not yet been fully studied. Mr. Phillips emphasized that there are many unknowns regarding future carbon regulation, and that it would be imprudent to plan on the assumption of strict carbon constraints in a very short time period. IIG Ex. No. 3, pp. 1-10 (Phillips Cross-Answering).

The Petitioner responded to the CCS issues concluding that while initial indications are very promising, uncertainty remains regarding CCS and further study is warranted. According to Petitioner's witness Mr. Moreland, CATF/IWF witness Mr. Cortez significantly understates the work necessary to accomplish partial carbon capture, and more study is required of both the carbon capture for the plant and the potential sequestration options. Pet. Ex. No. 19, pp. 5-8 (Moreland Rebuttal). Petitioner witness Ms. Radcliffe enumerated numerous issues associated with sequestration including the feasibility and cost of permanent geologic storage, insurance, legal liability issues, property rights, regulatory issues, and public acceptance of the technology, all of which require further study and, possibly, state and federal legislation. Pet. Ex. No. 21, pp. 3-12 (Radcliffe Rebuttal).

Ms. Radcliffe further detailed in her testimony that Duke Energy continues to study sequestration through the U.S. DOE Regional Carbon Sequestration Partnerships. Of particular interest is a DOE Phase II project at Duke Energy Kentucky's East Bend coal plant, at which sequestration potential will be tested in geology very similar to that at the Edwardsport site. Additionally, Petitioner has applied to take part in a DOE Phase III project, using the CO_2 from the Edwardsport IGCC Project, to test the feasibility of carbon capture and the geological sequestration of large volumes of CO_2 over a four year period. Ms. Radcliffe testified that as a Phase III project participant, Duke Energy Indiana would have access to a broad range of expertise and gain a valuable internal knowledge base. *Id.* Pet. Ex. No. 21, pp. 3-12

Petitioner's witness Ms. Pashos emphasized that the IGCC Project is first and foremost an environmentally and economically sound way to meet baseload capacity needs. However, she also indicated that the Company is committed to exploring CCS for the future. In her testimony Ms. Pashos outlined Duke Energy Indiana's contemplated path forward for CCS at the proposed IGCC Project and identified the following commitments, all subject to future Commission approval and cost recovery authorizations:

- To conduct a FEED study specifically targeted at understanding the costs and performance impacts of partial (15-18%) CO_2 capture at the IGCC Plant in the 2008 timeframe.

- To conduct a study (or studies) to determine feasible and acceptable sequestration options through either the DOE Phase III program, EOR, or other sequestration opportunities in the 2008 timeframe.

- To take reasonable steps during the detailed engineering and construction phase of the Project to include infrastructure, as identified in a carbon capture FEED study, to support 15-18% carbon capture.

- To initiate a case before the Commission to address CCS and EOR issues within six months following the granting of CPCNs for the IGCC Project. The purpose of the case will be to provide details to the Commission and other interested parties about the proposed studies, and to seek Commission approval to move forward with the above-mentioned activities.

- To work with interested parties toward state legislation constructively addressing potential liability and land rights issues associated with CCS.

- To seek necessary regulatory and environmental permitting for CCS and EOR if all other actions are approved by the Commission.

- To meet with the OUCC, CATF, and IWF to update them on progress.

Ms. Pashos testified that she believes that pursuing CCS in this manner is beneficial and represents an environmentally and economically sound policy to prepare for a carbon constrained future. Pet. Ex. No. 17, pp. 2-5, 13-15 (Pashos Rebuttal).

C. Commission Discussion and Findings on Carbon Capture and Sequestration. Based on the evidence presented in this proceeding the Commission recognizes that, regardless of the current lack of consensus regarding the scope or cost of restrictions, future regulation of CO_2 emissions appear likely. Given that probability, the Commission finds that carbon capture and sequestration technology may hold the potential for the continued cost effective utilization of Indiana coal in an environmentally responsible manner. Nonetheless, the Commission also recognizes that carbon emissions are not currently subject to regulation and existing regulatory and technical uncertainties present obstacles to the short term deployment of CCS technology.

Despite such regulatory and technical uncertainties, the Petitioner has presented a proposal in this proceeding to continue its efforts to prepare for a future in which carbon is regulated. The Commission accepts Petitioner's assurances that it will move forward in the manner outlined in its testimony in this Cause and make such assurances a condition of this Order. Given the inherent relative environmental benefits of IGCC the Commission finds that it is reasonable for Petitioner to move forward as planned consistent with these findings. Therefore, the Petitioner shall return to the Commission within six months of the granting of this CPCN with a filing that outlines its plans to develop carbon capture and sequestration study proposals. In undertaking carbon capture and sequestration study proposals the Petitioner should, to the extent practicable, utilize resources from universities located within the state of Indiana.

12. **Requested Ratemaking/Accounting Treatment.**

A. Petitioner's Requested Ratemaking/Accounting Relief. In its case-in-chief, Duke Energy Indiana sought approval of certain ratemaking and accounting treatment for the IGCC Project, including:

- Timely recovery of its construction financing and operating and maintenance, including depreciation and property taxes, costs incurred in connection with the IGCC Project;
- The use of accelerated (20-year) depreciation;
- An incentive associated with the IGCC Project equal to an incremental 200 basis points on the return on shareholder equity that would otherwise be earned by the Company over the life of the project;
- Deferral of post-in-service carrying costs and O&M costs (including depreciation and property taxes) on an interim basis until such costs are reflected in Duke Energy Indiana's retail rates; and
- Recovery of Duke Energy Indiana's external costs related to the development and presentation of the case.

Pet. Ex. No. 2, pp. 18-19 (Pashos Direct).

In addition, the Company requested that the Commission conduct an ongoing review of the construction of the IGCC Project as it proceeds. The Company initially requested approval of interim cost recovery of costs that needed to be incurred on the IGCC Project prior to the expected date of a Commission Order in the CPCN proceeding. However, the Company subsequently withdrew that request, as was discussed at the outset of this Order.

1. IGCC Rider/Accounting Treatment. Mr. Stephen Farmer, a consultant for Duke Energy Indiana, testified regarding the Company's proposed Standard Contract Rider No. 61 (the "IGCC Rider"). According to Mr. Farmer, the IGCC Rider is a combination rate recovery mechanism that incorporates many of the attributes of Duke Energy Indiana's Rider 62 (the Qualified Pollution Control Property Revenue Adjustment) and Rider 71 (the Clean Coal Operating Cost Revenue Adjustment). The IGCC Rider will be used to recover the construction work in progress ("CWIP") financing costs; the operating and maintenance costs including depreciation and property taxes; and the external costs incurred in connection with the IGCC Project.

Table 1 in Mr. Farmer's direct testimony details the costs that would flow through the proposed IGCC Rider. According to Mr. Farmer, under the IGCC Rider, O&M expenses would include: (a) increased payroll costs, including payroll taxes and employee benefits, to be determined based on Duke Energy Indiana's payroll tax and fringe benefit loading rates; (b) property insurance applicable to the IGCC Project; and (c) the amortization of external costs relating to the development of regulatory filings associated with the IGCC Project including outside consulting costs relating to this proceeding. Mr. Farmer explained that the Company would reduce O&M expense recovery by the O&M expenses applicable to the retiring Edwardsport steam generating plant that are recovered in base rates ($5,756,000 on an annual basis, before jurisdictional allocation). Pet. Ex. No. 13, pp.3, 5, 7, 14-16 (Farmer Direct).

Mr. Farmer indicated that the IGCC Rider would recover property tax expense applicable to the IGCC Project as recorded on the Company's books and records, reflecting the property tax abatements and Tax Increment Financing credits. He indicated that customers would receive a credit for retiring Edwardsport steam generating station property taxes included in rates, in accordance with the provisions of the Commission's Order in Cause No. 42359 (*Ind. Util. Reg. Comm'n,* May 18, 2004) whereby the difference between the *pro forma* level of property tax expense included in the jurisdictional cost of service and actual property taxes paid after jurisdictional allocation are credited back to customers via Rider 62. *Id.* at 7-10.

Mr. Farmer stated the Company proposed to update its IGCC Rider costs every six months, with supporting testimony and exhibits similar to the type of information typically presented in Rider 62 and 71 proceedings. The IGCC Rider will apply to all retail customers served under the Company's firm power tariff rates and will be billed to individual customers within a retail rate group based on billed kWh sales, except for industrial customers served under Rate HLF. Mr. Farmer indicated that the Company proposed that the allocation of recoverable costs within Rate HLF be based on kW sales as opposed to a kWh basis, which is consistent with the rate design principles approved by the Commission in the Company's Phase 1 CAIR/CAMR environmental compliance case in Cause Nos. 42622 and 42718 (*Ind. Util. Reg. Comm'n*, May 24, 2006). *Id.* at 14-16.

Mr. Farmer testified that the accounting treatment for which the Company is seeking approval is consistent with, if not the same as that which the Commission has authorized in the Company's various environmental proceedings. He also testified that the Company has accounting procedures in place that stop the accrual of AFUDC on the portion of environmental project capital costs receiving retail CWIP ratemaking treatment and that these same procedures will be applied to IGCC Project costs. Duke Energy Indiana also has procedures in place that recognize the difference in ratemaking between retail and wholesale jurisdictions with respect to environmental costs, which will be applied to IGCC Project costs. *Id.* at 18-19.

Mr. Farmer explained that the Company is proposing to be allowed to continue the accrual of AFUDC and deferral of operating expenses after the in-service date of the IGCC Project, to the extent that costs are not reflected in Duke Energy Indiana's retail electric rates (*i.e.*, through the IGCC Rider or in base rates). The differential between post-in-service costs recovered in rates and actual costs incurred will be relatively small if the Company's proposed IGCC cost recovery mechanism is utilized. The Company will file its initial request for recovery of costs related to the IGCC Project after the Commission's Order is issued – and is requesting that the six-month restriction on filing for CWIP ratemaking treatment applicable to qualified pollution control projects not apply to the IGCC Project. *Id.* at 18.

Mr. Farmer stated that the Company will recover fuel costs applicable to the IGCC Project through its FAC and that emission allowance costs will be recovered through its emission allowance cost recovery mechanism. The IGCC technology will allow the Company to use more high sulfur Illinois Basin coal, which should result in future fuel savings. Mr. Farmer also explained that the recovery of IGCC Project costs will be included in FAC earnings and expense tests calculations in the same manner that the recovery of environmental financing costs and operating expenses are handled. *Id.* at 20-21.

Mr. Farmer described the estimated rate impacts expected from the IGCC Project and explained that the estimates did not attempt to account for the expected lower fuel and emission allowance costs associated with this plant. After the FEED Study was completed and the Company had a more up to date estimate of the cost of the Project, Mr. Farmer updated the rate impact analysis in rebuttal testimony, demonstrating that the rate impacts from the IGCC Project would be phased in over the construction period and were estimated to result in an overall total class rate impact of approximately 16% if Duke Energy Indiana owns 100% of the plant. Again, this updated estimate did not attempt include credit for expected lower fuel and emission allowance costs associated with the Edwardsport IGCC Project. *Id.* at 21-22; Pet. Ex. No. 28-E (Farmer Rebuttal).

2. **Ratemaking Treatment for Tax Incentives.** Mr. Farmer also explained the Company's proposed ratemaking treatment relating to various state, local and federal tax incentives applicable to the IGCC Project. The Company proposed to credit the reduction in tax expense through the IGCC Rider. He then explained that the Company proposed to credit customers through the IGCC Rider for its reduction in property taxes through the ten-year abatement and the TIF reimbursement, both of which were awarded to the Company by the Knox County Council. Pet. Ex. No. 13, p. 8 (Farmer Direct).

Mr. Farmer testified with respect to how the Company proposed to incorporate the recovery of IGCC Project property taxes in rates while honoring the commitments regarding property taxes made in the Company's last rate case. The Company proposed that property taxes applicable to the IGCC Project be recovered through the IGCC cost recovery mechanism because by tracking IGCC property taxes, the Company will neither over nor under recover IGCC Project property taxes. According to Mr. Farmer, while the Company's commitment in the rate case to bear the risk of increases in property taxes will remain intact, it will exclude IGCC Project property taxes. *Id.* at 9.

Mr. Farmer then described the federal clean coal investment tax incentives for which the Company has applied. He explained that the primary benefit to the recipient of the tax credit is that, by using the investment tax credit to offset federal income tax liabilities that would otherwise be payable, the Company is able to preserve a larger share of internally generated funds that can be used to fund necessary capital expenditures thereby reducing the Company's need to fund capital expenses with outside capital. Mr. Farmer also stated that the tax credit is front-end loaded, which is especially important during the initial construction period when large sums of new capital must be raised. The Company proposed to amortize the federal clean coal investment tax credits ratably over the proposed regulatory life of the IGCC Project. Duke Energy Indiana proposed to pass the jurisdictional portion of this credit through to retail customers through the IGCC Rider. *Id.* at 10-13.

3. **Incentive Return on Equity/Accelerated Depreciation.** As provided under IC 8-1-8.8-11(a)(2), Duke Energy Indiana initially requested an incentive associated with the IGCC Project equal to an incremental 200 basis points on the return on shareholder equity ("ROE") that would otherwise be earned by the Company over the life of the IGCC Project. In its rebuttal filing, the Company agreed to reduce its request to an incremental 150 basis points on ROE, in consideration of the rate impact on customers. Additionally, as provided under IC 8-1-2-6.7 and IC 8-1-8.8-11, Duke Energy Indiana also initially requested the use of accelerated (20-year) depreciation for the IGCC Project. However, Duke Energy Indiana subsequently withdrew this request and instead requested approval to use a standard 30-year depreciation for this Project. Pet. Ex. No. 2, p. 19 (Pashos Direct); Pet. Ex. No. 17, p. 11 (Pashos Rebuttal).

With respect to the incentive ROE, Ms. Pashos explained that she believes the Company's request for this incentive is reasonable in light of the General Assembly's encouragement of clean coal technology and coal gasification, Duke Energy Indiana's efforts to obtain benefits for customers in terms of local, state and federal tax incentives, and the economic development benefits the Project is expected to bring to the state. Ms. Pashos noted that Duke Energy Indiana has worked very hard to undertake this Project in a manner that creates value for its customers through obtaining IGCC Project tax credit incentives at the federal, state and local levels – over $450 million of tax credit incentives in total, which will flow through Petitioner's rates to benefit customers. Pet. Ex. No. 2, pp. 19-20, 22 (Pashos Direct); Pet. Ex. No. 17, pp. 10-11, 15-20 (Pashos Rebuttal). Ms. Pashos concluded that the Company's ratemaking request is reasonable and entirely consistent with the intent of the Indiana General Assembly – which has provided both tax incentives and ratemaking and accounting incentives for projects such as the IGCC Project. Pet. Ex. No. 2, pp. 19-20 (Pashos Direct).

Ms. Lynn Good, Vice President and Treasurer of Duke Energy Corporation, explained the importance of the additional 150 basis points on the return on equity for the IGCC Project for providing the strong cash flow generation and retained earnings integral to the financing of these capital expenditures. This incentive will also help maintain the strong credit metrics necessary for cost-effective access to the capital markets. Ms. Good explained that the Company's customers benefit from achieving a high level of credit quality through lower overall financing costs and greater access to the capital markets. Pet. Ex. No. 10, p. 11 (Good Direct). Ms. Good indicated that recovery of its expenditures related to the IGCC Project and approval of its other ratemaking and accounting relief is of increasing importance to the maintenance of the

Company's financial strength during the building cycle, especially in light of the Company's capital commitments for maintenance and environmental compliance. *Id.* at 12.

Mr. Steven Fetter, President of REGULATION UnFETTERED, stated his belief that the Indiana General Assembly enacted its clean coal project incentive legislation because it desired that the Commission use the incentives to encourage clean coal projects. He then said that, in light of this recently enacted legislation, the financial community would have concerns about whether the Commission would continue the constructive regulatory approach for which it is highly regarded, if the Commission were to forego use of the clean coal incentives to encourage Duke Energy Indiana's IGCC Project. Pet. Ex. No. 11, pp. 20-21 (Fetter Direct).

B. OUCC and Intervenors' Evidence and Petitioner's Response.

1. Incentive ROE. Witnesses for the OUCC, IIG, and the CAC uniformly opposed Petitioner's request for an incentive ROE. OUCC witness Mr. Wes Blakley testified that the Company's rate of return is commensurate with peer utilities with similar risk profiles and fairly compensates it for its investments in the IGCC Project, given the current economic climate. Mr. Blakley said that, if the IGCC Project is approved by the Commission with the incentives provided under IC 8-1-8.8, customers will bear the financial risk of an unprecedented amount, nearly $2 billion. Further, Mr. Blakley indicated that past requests for enhanced rates of return on shareholder equity have not been approved by the Commission; rather such cases resulted in settlements. Public's Ex. No. 3, pp. 4-5 (Blakley Direct).

Mr. Blakley also reminded the Commission of the significant incentives provided to the Company without an enhanced return. He mentioned the ability to recover investments in Qualified Pollution Control Property through a tracking mechanism, earning a return of and on this capital investment as well as receiving the benefits of accelerated depreciation and tracked O&M expenses. Mr. Blakley stated that the OUCC contends that Indiana's clean coal technology statutes provide adequate financial security for utilities and that any financial risks that arise in the construction of these projects are virtually eliminated by statute. *Id.* at 5-8.

IIG witness Mr. Michael Gorman stated that Duke Energy Indiana's initial request for a 200 basis point incentive return on equity to its last authorized return on equity should be rejected. Mr. Gorman compared the Company's return on equity with the industry average for integrated electric utility companies in 2006, which was 10.36%, and determined that the Company's return on equity was an above industry average return. He also mentioned that the 10.5% return on equity provides the Company with a premium of around 4.5 percentage points over its current marginal cost of debt (approximately 6.2% or 6.0%). Based on these factors, Mr. Gorman concluded that 10.5% was fair and reasonable compensation for the Company's investment risk and will support the Company's current and targeted bond ratings. IIG Ex. No. 2, p. 3 (Gorman Direct).

Mr. Gorman further indicated that it would be unfair of the Commission to require customers to pay for an incentive equity return while the IGCC Rider's tracking mechanism shifts the Company's investment risk to customers. Mr. Gorman also stated that the credit rating agencies would consider the proposed IGCC Rider as a positive due to the reduced operating risk to Duke Energy Indiana. *Id.* at 3-4.

Mr. Gorman stated that another factor considered by credit agencies in assessing ratings is the need for the utility to maintain competitive cost structures and retail rates. He said that this factor is critical because a utility's customers must be able to pay for utility service. Otherwise, Mr. Gorman stated, customers will be forced to consider alternative sources of energy or to relocate their production facilities. He stated that an important element in maintaining credit quality is to develop a regulatory mechanism to provide the utility a good probability of full cost recovery, and that will also result in just and reasonable and competitive rates to end-use customers. *Id.* at 4.

CAC witness Mr. Biewald recommended denial of the Company's requested ratemaking treatment, including its requested enhanced return on equity. RC Ex. B, p. 5, 47-49 (Biewald Direct).

In her rebuttal testimony, Ms. Pashos indicated that she believes the requested ROE incentive is consistent with the legislature's stated intent to "encourage the use of advanced clean coal technology, such as coal gasification." IC 8-1-8.8-1. She also noted that the language of the statute indicates that the incentive was designed to encourage certain activities by Indiana utilities and does not require justification in terms of risk profile or credit quality concerns. Ms. Pashos stated that policy reasons support a full incentive in this case, but that the Company had reduced its request to a 150-basis point incentive, in order to mitigate the rate impact of the IGCC Project. Pet. Ex. No. 17, pp. 10-11, 15-20 (Pashos Rebuttal). On cross-examination, Ms. Pashos indicated her belief that the Commission retains important discretion in this area – both to determine the reasonableness and necessity of the proposed Project, as well as the amount of any ROE incentive (up to a maximum of 300 basis points additional ROE). But, she also emphasized her belief that the General Assembly clearly intended for projects that meet the requirements of IC 8-1-8.8-1 receive an incentive to its existing ROE.

Duke Energy Indiana witness Mr. Fetter indicated that Indiana's clean coal legislation does not include a financial integrity test before an incentive ROE can be awarded. Instead, he stated that the law provides a true incentive apart from traditional ratemaking in order to encourage what the legislature views as beneficial utility behavior from a public policy standpoint. He maintained that the legislature intends to have Indiana utilities continue to rely upon the state's coal resources in a forward-thinking environmental manner. Mr. Fetter stated that he believes the IGCC Project is wholly consistent with the legislative findings and policy objectives of the law. Pet. Ex. No. 26, p. 3 (Fetter Rebuttal).

2. **Depreciation Issues**. Witnesses for the OUCC and IIG contended that the Company's assumption of a 20% negative net salvage for the IGCC Plant was not reasonable and should be rejected. IIG witness Mr. Gorman argued that because the Company has not yet established what its cost of removal of the IGCC Project would be, the proposed 20% net salvage cost is not based on a complete and credible study and should be rejected as not known and reasonably measured. He also explained that a negative net salvage of 20% increases the depreciation rate on the IGCC Project from 5% to 6%, which has a meaningful impact on the annual revenue requirement of the IGCC Project. Mr. Gorman also stated that the proposed accelerated (20 year) IGCC depreciation would produce credit rating financial metrics that are much stronger than needed to support the Company's current and targeted bond ratings. IIG Ex. No. 2, p. 4 (Gorman).

OUCC witness Mr. Blakley testified that there is no mention of "negative net salvage value" in any of the clean coal technology statutes. Mr. Blakley then explained that the design life of the IGCC Project is 30 years, which means that its rate of depreciation is 3.33% per year. But, he stated that when this amount is grossed up with the 20% negative net salvage value factor, it becomes a depreciation of approximately 4%. The depreciation rate requested by the Company fully compensates it for any negative net salvage value based on the 30 year life of the facility. Mr. Blakley explained that each additional one percent amounts to an additional cost of $16 million for Duke Energy Indiana's customers. Public's Ex. 3, pp. 7-8 (Blakely).

Mr. Roebel testified in response to the concerns raised on this issue, that the Company is not proposing to place depreciation rates into effect until the plant goes into operation, and then only after a depreciation study, including a study of the cost of decommissioning the plant. He stated that depreciation expenses, including decommissioning costs, will be a cost of using the plant to serve customers and should be considered. However, in light of Intervenor and OUCC questions, the Company reviewed its approach and is now proposing a 10% negative net salvage value. Mr. Roebel indicated that the IGCC Project will have a much lower profile than a pulverized coal plant and that the cost of dismantling should be less costly. Pet. Ex. No. 27, p. 7 (Roebel Rebuttal).

Mr. Farmer explained that the concept of recovering costs relating to negative net salvage, whether they be costs incurred due to interim retirement or replacement of property or whether they be final decommissioning costs incurred at the end of a project's life, is a standard and accepted part of normal ratemaking. He stated that the Company now estimates that a more likely percentage of negative net salvage is closer to 10% than 20% and that he has included this value amount as a placeholder in the rate impact analysis. Pet. Ex. No. 28, p. 2 (Farmer Rebuttal).

Ms. Pashos testified that in order to help mitigate the rate impact, the Company was withdrawing its request for accelerated 20 year depreciation and seeking a traditional 30-year depreciation life. Mr. Farmer testified that unlike the Company's request related to the negative net salvage value, the Company is proposing that the Commission find and approve a thirty-year depreciation life for the IGCC Project. Mr. Farmer also indicated that he included the thirty-year life in his updated rate impact analysis. Pet. Ex. No. 17, p. 11 (Pashos Rebuttal); Pet. Ex. No. 28, p. 3 (Farmer Rebuttal).

3. Non-Native Sales / Wholesale Native Load Sales Issues. OUCC witness Ms. Soller testified that because this plant was not included in the calculation of the target value of non-native sales profits in Duke Energy Indiana's last rate case and because the capital cost of the IGCC plant is substantially higher than the cost of the Company's average production fleet, the Company should be required to credit its ratepayers with 90% of any wholesale power sale margins from generation at the IGCC plant, with the remaining 10% net profits going to shareholders. In the alternative, the OUCC believes wholesale power sales margins from this facility should be subject to the same 50-50 sharing mechanism that was approved in the Company's last base rate case. Public's Ex. No. 1, pp. 10-11 (Soller).

In her rebuttal testimony Ms. Pashos began by making the assumption that Ms. Soller was referring to non-native, off-system sales profits that may result from the IGCC Project, as opposed to firm wholesale native load sales revenues – which she indicated were quite different in that they receive a full allocation of fixed production costs not borne by retail customers. Ms.

Pashos testified that under the Company's proposal retail customers will share in any non-native, off-system sales profits ultimately created by this Project through the Commission approved Standard Contract Rider No. 70 ("Rider 70") sharing mechanism.

Ms. Pashos indicated that to the extent that the OUCC is recommending a different level of non-native off-system sales profits be built into base rates, any such proposal is quite premature. The plant is not even approved or built yet, and there is no fixed, known, or measurable data to support such a proposal. Further, under Rider 70, non-native, off-system sales profits are tracked and shared above the level built into base rates, thus retail customers will participate in any increases (from whatever source) in net non-native sales profits. Ms. Pashos also indicated that Ms. Soller's 90% sharing mechanism may be administratively burdensome to implement and that the IGCC plant is expected to be one of the lowest costs units on the Duke Energy Indiana system, and as such will dispatch toward the bottom of the economic stack and will realistically be used to serve native load customers' needs, and not off-system, non-native sales. Pet. Ex. No. 17, pp. 20-21 (Pashos Rebuttal and testimony at hearing).

4. **Deferred Taxes.** IIG witness Mr. Gorman stated that Duke Energy Indiana's proposed treatment of deferred tax balances related to the IGCC Project was unreasonable because by including the IGCC deferred tax balance in its total company capital structure, the Company will be spreading these deferred tax balances across all of its regulated utility costs of service, not just the IGCC Project cost of service. He stated that this proposal is inconsistent with Duke Energy Indiana's proposal to recover the IGCC Project costs separately through the IGCC Rider. Mr. Gorman believes that all tax costs and benefits should be reflected in the IGCC Rider. IIG Ex. 2 p. 5 (Gorman).

In his rebuttal testimony Mr. Farmer ultimately agreed with Mr. Gorman's proposal that IGCC tax costs and benefits be captured separately and specifically within the IGCC Rider and that the accumulated balance of deferred income taxes generated by the IGCC Project be treated as a deduction from the cost of plant when calculating jurisdictional revenue requirements. Mr. Farmer also opined that the calculation of financing costs on a newly constructed plant such as the IGCC Project can be significantly understated when the capital structure used to determine jurisdictional return on investment includes the book balance of accumulated deferred income taxes in the capital structure. Mr. Farmer explained that the IGCC Project will not generate any deferred income taxes during construction period. He indicated that the estimated accumulated deferred income tax balance attributable to the IGCC Project does not reach the 12+% included in the Company's calculation of the weighted average cost of capital until 2023. Mr. Farmer concluded that if accumulated deferred income taxes are included in the capital structure used to determine the return requirement applicable to the IGCC investment, then the Company would significantly under-recover the cost of financing the project. Pet. Ex. No. 28, pp.4-6 (Farmer Rebuttal).

5. **Investment Tax Credit Ratemaking Treatment.** IIG witness Mr. Gorman discussed the two options for treatment of the federal investment tax credits – either credit the deferred balances back to customers using an amortization of the balance, or use of the unamortized balance as an offset to rate base. Mr. Gorman believes that the Company should perform a revenue requirement comparison of these two options and that the Commission should select the option that results in the lower cost revenue requirement. IIG Ex. 2, p. 6 (Gorman).

In his rebuttal testimony Mr. Farmer indicated that Duke Energy Indiana did perform such a comparison in response to the issue raised by Mr. Gorman, and explained that the comparison includes an estimate of jurisdictional revenue requirements over the thirty-year regulatory life of the IGCC Project. According to Mr. Farmer, the two methods produce different results when compared on a year-to-year basis. Mr. Farmer explained that the rate base reduction method results in a larger credit during the first half of the asset's life offset by a smaller credit in the last half of the asset's life. The most obvious consequence of choosing this method is that current customers will benefit to the detriment of future customers. Mr. Farmer stated that a second consequence is a significant reduction in the Company's cash flow (approximately $60 million during the first half of the IGCC Project's regulatory life). He indicated that the Company believes that the positive benefits of the tax credit would be significantly eroded if the credit is flowed through to customers on an accelerated basis. This method would reduce the cash flow to the utility at just the time the cash flow was most crucial, during the construction phase. For these reasons, Mr. Farmer indicated that the Company is opposed to this change. Pet. Ex. No. 28, p. 9 (Farmer Rebuttal).

On cross examination, Mr. Farmer indicated that customers at the beginning of the plant's life do not benefit by an increase to the accumulated depreciation reserve because the Company would not yet have accumulated large amounts of depreciation. TR. J-37. Therefore, customers pay higher rates during the first part of the IGCC plant's life because there is less accumulated depreciation. TR. J-40. He testified that rates trend downward as depreciation accruals lower the IGCC return requirement. Pet. Ex. 28, p. 15 (Farmer Rebuttal).

6. Reconciliation of O&M Expenses. IIG witness Mr. Gorman opposed the Company's requested reconciliation adjustment mechanism for O&M costs in its IGCC Rider. He stated that the IGCC Rider would not be in effect for an extended period of time, and projected operating costs should be reasonably consistent with actual operating costs. Mr. Gorman indicated that the proposed reconciliation adjustment would eliminate incentives to manage costs in between semi-annual rate factor adjustments because all cost increases would be passed on to customers. He also said that he believed the reconciliation adjustments to the proposed factor would only increase rate volatility, resulting in higher costs to retail customers. Mr. Gorman stated that the Commission should discourage the Company from overstating IGCC projected operating costs in the IGCC Rider by ensuring that such costs are considered in all earnings tests applicable to other Company rate mechanisms, particularly the fuel mechanism. IIG Ex. 2, pp. 19-20 (Gorman).

Duke Energy Indiana witness Mr. Farmer responded that the reconciliation feature included in the Company's IGCC Rider was included to provide equal protection to customers and the Company. He stated that the reconciliation of costs is commonly used in cost recovery mechanisms and is an accepted form of ratemaking. Mr. Farmer testified that projected operating expenses that may be recovered are required to be trued up pursuant to IC 8-1-8.8-12(f). Mr. Farmer indicated that the Company's proposal protects customers from being overcharged due to variances between actual and projected costs, and due to differences between actual and estimated kilowatt and/or kilowatt-hour sales used to develop billing factors. The Company is protected from under billing customers for the same reasons. Mr. Farmer then clarified that the Company has always planned to incorporate the recovery of the IGCC Project costs in FAC earnings and expense test calculations. Pet. Ex. No. 28, pp. 10-11 (Farmer Rebuttal).

7. **IRP Costs**. OUCC witness Mr. Blakley testified that the Company appears to request recovery of the costs associated with their 2005 IRPs in this proceeding. He said that, if that is indeed the case, the OUCC contends that IRP studies are part of the normal business operations of a utility and were embedded in base rates during the Company's last rate case. Public's Ex. No. 3, p. 10-11 (Blakley). In response to this issue Mr. Farmer stated that the Company will agree to forgo the recovery of IGCC-related 2005 IRP costs and will not include them in any future IGCC filings. Pet. Ex. No. 28, p. 12 (Farmer Rebuttal).

8. **Transmission Cost Recovery**. Ms. Soller indicated that to the extent the Commission approves the cost recovery of the IGCC Project transmission costs, and a portion of those costs will ultimately be shared among Midwest ISO members through the Regional Expansion and Criteria Benefits ("RECB") process, she recommends that the Company's recovery be reduced proportionately. Public's Ex. No. 1, pp. 17-18 (Soller). Mr. Farmer agreed that in the event the IGCC Project costs are paid for in part by other Midwest ISO members as part of the RECB process, then Duke Energy Indiana would proportionately reduce its request for recovery of such costs through its proposed IGCC Rider. Pet. Ex. No. 28, p. 11 (Farmer Rebuttal).

9. **Rate Impact**. The OUCC and Intervenors testified that the rate impact associated with the IGCC Project is higher than the increase approved in the Company's last base rate case. IIG Ex. 1, p. 2 (Phillips Direct); Public's Ex. No. 1, p. 5 (Soller). CAC witness Mr. Biewald contended that the Company's analyses did not include all the requested ratemaking and therefore did not provide an accurate picture of the true costs of the IGCC Project. Mr. Biewald also indicated that the Company did not include the impact on the system of the fuel and emission allowances costs associated with the IGCC Project in its analysis. RA Ex. B, pp. 30-31 (Biewald Direct).

In response to this issue Duke Energy Indiana updated its rate impact analysis in the rebuttal testimony of Mr. Farmer. Mr. Farmer explained that this analysis includes all the updated assumptions for the Company's proposed ratemaking treatment, including 30 year depreciation, 10% negative net salvage value, and the 150 basis point ROE incentive. Pet. Ex. No. 28, pp. 2, 4, 8, 15 (Farmer Rebuttal).

Mr. Farmer indicated that the rate increase associated with the IGCC Rider will be phased in over the construction period to a peak impact of between 15% to 19%, depending on the rate class, with an overall total retail class rate impact of approximately 16% based on 100% ownership of the IGCC plant. *Id.* at 15-16. Pet. Ex. No. 28-D, 28-E. Mr. Farmer testified that the rate impact analysis did not include an estimate of how the addition of the IGCC Project will affect fuel costs and/or emission allowance costs. However, Mr. Farmer further indicated that this only serves to make the Company's rate impact analysis conservative because the IGCC Project is projected to be one of the lowest variable cost units on the Duke Energy Indiana system and therefore the system fuel and EA costs are lower than they otherwise would have been with the alternative plan without the IGCC. *Id.* at 13.

Ms. Pashos testified that while the Company recognizes the rate impact is significant in the peak year (first full year of operation of the plant), the rate impact is generally in line with historical rate increases from previous additions of baseload generating plants in Indiana. Pet. Ex. No. 2, p. 22 (Pashos Direct).

13. Commission Discussion and Findings on Ratemaking and Accounting Requests.

A. IGCC Rider. As discussed previously pursuant to IC 8-1-8.8 an "eligible business" must file an application for approval of a "clean coal and energy project" and the Commission, after notice and hearing, shall issue a determination of a project's eligibility for financial incentives provided under the statute. The relevant financial incentives involved in this proceeding are the timely recovery of costs; authorization of up to three percentage points (300 basis points) on the return on shareholder equity that would be otherwise allowed to be earned on the projects; and other financial incentives the Commission considers appropriate.

IC 8-1-8.8-12 details the procedure and requirements for the timely recovery of cost incentives and indicates in relevant part that an eligible business seeking timely recovery of its costs must apply to the Commission for approval of a rate adjustment mechanism. Consistent with this statute, Duke Energy Indiana submitted a detailed schedule for completion of the construction of the new generating facility, a copy of the most recent integrated resource plan filed with the Commission, the amount of capital investment in the new energy generating facility and other information deemed necessary by the Commission. Duke Energy Indiana also demonstrated that it is an "eligible business" and the Edwardsport Project will utilize clean coal technology as discussed herein and constitutes a coal gasification facility as that term is defined in the statute.

Under the terms of the Statute, the Commission shall allow the timely recovery of costs associated with a qualified utility's system property if the applicant provides substantial documentation that the expected costs associated with qualified utility system property are reasonable and necessary. Based on this statutory framework, and as discussed further herein, the Commission finds that the Edwardsport IGCC Project is eligible for the "timely recovery of costs" incentive under the statute. The issue of Duke Energy's request for an enhanced return of up to three (3) percentage points on the return on shareholder equity that would be otherwise allowed to be earned on the projects is discussed separately herein.

The Commission is mindful that the IGCC Project is the first proposal to build a baseload generating plant in the State of Indiana since the 1980s, and that with such an undertaking come significant financing and capital costs. We are cognizant of the Indiana General Assembly's encouragement of new generating facilities that utilize Indiana coal and clean coal technology, such as coal gasification under IC 8-1-8.8, and that the Governor's Home Grown Energy Plan also encourages generation additions to meet Indiana's growing electricity needs. Therefore, we have approved specific statutory incentives in this Cause as set forth in this Order. We further find that Petitioner's proposed IGCC Rider is approved for use and for the recovery of the approved IGCC Project costs, including financing, O&M, depreciation, property taxes, payroll costs, and property insurance costs as proposed by Petitioner. Additionally, we approve Petitioner's request for deferral of post-in-service carrying costs and O&M costs on an interim basis until such costs are reflected in Duke Energy Indiana's retail rates.

With respect to the specific issues raised by the Intervenors related to Duke Energy Indiana's IGCC Rider we address each of these issues as follows. With respect to depreciation issues, we agree with Duke Energy Indiana that a depreciation and cost of removal study will be necessary prior to the IGCC Project going in-service and direct that Duke Energy Indiana conduct such a study and provide the results of such study to the Commission in one of its semi-annual IGCC Rider filings prior to the IGCC Project going into service. The proper amount of negative net salvage associated with the IGCC Project should be a determination that comes out of that study and may be reviewed or challenged by the OUCC and any interested Intervenors at that time. We also find reasonable and approve Duke Energy Indiana's revised request for 30-year depreciation for the IGCC Project.

With respect to the issue of whether deferred taxes should be included in the cost of capital attributed to the IGCC Project in the IGCC Rider, we agree with IIG witness Mr. Gorman and Mr. Farmer's rebuttal position, that ratemaking could reasonably exclude such costs from the capital structure and include the deferred tax balance related to the IGCC Project as an IGCC rate base offset. As the estimated accumulated deferred income tax balance attributable to the IGCC Project does not reach the level included in the Company's calculation of the weighted average cost of capital until 2023, we agree that reflecting the costs in the IGCC Rider would result in a lower authorized return on the costs of financing the project. The CWIP rules provide for a utility to use "the appropriate amount, ratio, and cost rate as of the date of valuation of the utility's qualified pollution control property under construction for such capital structure components as deferred taxes, customer deposits, and investment tax credits." 170 IAC 4-6-14 (1)(c). We find the CWIP rules provide sufficient discretion in this regard because the rules recognize that the appropriate amounts and types of capital structure components included in the capital structure may be project specific.

Furthermore, The Commission generally considers credit quality to relate strongly to the availability of funds to pay debt capital cost. The ordinary treatment of deferred taxes could understate the project specific financing cost as noted by Mr. Farmer (Pet. Ex. 28, pg. 6). The treatment proposed by Duke in its rebuttal testimony would appear to reduce this bias and serve as a financial incentive for the project. Petitioner's Exhibit 28-A highlights the impact on the weighted cost of capital. The ordinary treatment depicted on page 1 indicates a 7.05% return while the Duke rebuttal proposal authorizes a return of 8.77%. Further, modification of page 2 by replacing the common equity cost rate with that approved in Duke's most recent rate case equates to a return of 8.04%.

An increased rate of return early in the life of the project provides for the availability of additional funds to pay debt capital costs and is supportive of credit quality. As project life passes, the accumulation of project specific deferred income taxes reduce rate base faster than under the ordinary approach, providing for a reduced revenue requirement in the future. The Commission recognizes that this treatment of deferred income taxes acts as an additional incentive that serves to maintain credit quality and is consistent with the provisions set forth in IC 8-1-8.8-11(a)(5). Considering this benefit and the cost of attaining it, we find that excluding deferred income taxes from the capital structure and instead applying them as an off-set to rate base to be reasonable treatment in the conditions specific to this proceeding.

On the issue of the proper ratemaking treatment for the federal tax incentives, we agree with the Company's proposal and find that the rate base reduction method proposed by IIG witness Mr. Gorman would benefit current customers to the detriment of future customers, and would not provide for a proper match of costs with benefits. Additionally, we are cognizant that the benefit of the federal tax incentive is that under the amortization method, it provides a benefit to the Company when it is needed most, in the first years of construction of the project, when the capital requirements are the highest. We find the Company's proposal to amortize the benefit of the tax credits and to pass such benefits back to customers over the life of the plant in accordance with federal tax laws to be appropriate.

Testimony presented in this matter demonstrates that transmission costs related to the IGCC Project are appropriate for the inclusion in the cost estimate and hereby find that such costs are eligible for cost tracking incentives provided under IC 8-1-8.8. Additionally, we also agree with the OUCC's proposal, accepted by the Company, that if such transmission costs are partially reimbursed under the Midwest ISO's Regional Expansion and Criteria Benefits process, any costs recovered from Duke Energy Indiana retail customers associated with such transmission projects shall be proportionately reduced.

Regarding whether to include a reconciliation component to the IGCC Rider for O&M costs, the Commission finds that such feature is commonly used and that IC 8-1-8.8 specifically provides that any forecasted tracking mechanism must include a true-up. IC 8-1-8.8-12(f). Therefore, we approve the use of a true-up provision for this purpose.

With respect to the issue of the inclusion of 2005 IRP costs in this proceeding, we agree with the OUCC's proposal to exclude recovery of these costs as representative IRP costs are included as part of the Company's cost of service included in base rates.

We also find that in accordance with its proposal, the Company shall file a docketed proceeding semi-annually for recovery of the costs allowable under the IGCC Rider. Because the Company's requested IGCC Rider is requested under Ind. Code 8-1-8.8-12, which specifically provides for the use of forecasted data, we find that the Company is not required to wait until the IGCC Project has been under construction for six months before filing its first proceeding to recover the CWIP costs associated with the project.

B. Incentive ROE. We have previously concluded that the IGCC Project qualifies as a clean coal and energy project and that it is reasonable and necessary and therefore eligible for tracking incentives under IC 8-1-8.8. As previously discussed, IC 8-1-8.8 provides a number of financial incentives that may be awarded and monitored by the Commission. Of central importance is the statutory tracking mechanism that allows the Company to timely recover its costs for the IGCC Project from ratepayers with limited risk to shareholders.

In the present proceeding, in addition to the cost tracking incentives already approved by the Commission, Duke Energy Indiana also requested an enhanced return on shareholder equity of 1.5%. In Duke Energy Indiana's last rate case in Cause No. 42359 the Commission approved an ROE of 10.5%. Therefore, approval of this incentive would place the Company's ROE for the IGCC Project at 12%.

In considering this request we recognize that unlike the general over-arching incentive cost tracking mechanism approved by the Commission, IC 8-1-8.8-11(a)(2) provides a range from 0-3% for approval of an incentive ROE, which provides a degree of latitude to the Commission in its consideration of the request. Therefore, we find that in evaluating a request for an enhanced ROE we must first place the request in the context of our overall consideration of the issues in this Cause including our consideration and approval of other incentives. Second, we must also review and consider past determinations by the Commission with respect to the impact that trackers (such as the one provided in IC 8-1-8.8) have played in our overall consideration of the level of ROE.

In Duke Energy Indiana's last rate case in Cause No. 42359, in finding that a ROE of 10.5% was appropriate, the Commission specifically discussed the interplay between trackers and ROE and concluded that:

> ...*trackers reduce risk* to a utility....Therefore, we must--in reaching our determination regarding an appropriate cost of equity--properly consider the effect these trackers have in reducing risk, to ensure that these reduced risks are properly reflected in the cost of equity approved by the Commission.

Final Order in Cause No. 42359 at 53.

This proceeding presents obvious parallels to our discussion of the issues in Cause No. 42359. Under the provisions of IC 8-1-8.8, we have approved a tracking mechanism that will ensure cost recovery for the project, and we have also been asked to award an additional incentive in the form of an enhanced rate of return. In our consideration of the issues in Cause No. 42359, we recognized that trackers reduce risk and nothing in this matter indicates that the new cost tracking mechanism approved in this proceeding will act any differently.

We agree with the Company's witness, Mr. Fetter, that the Commission has discretion to determine what incentives to allow. Consideration as to whether an incentive return on equity is necessary to maintain a utility's credit rating is a factor that we can consider in exercising our discretion. We recognize that the value of timely cost recovery provided for in IC 8-1-8.8 is beneficial to the Company and provides a significant incentive that enhances a regulatory environment that is attractive to credit rating agencies resulting in good utility credit ratings and lower cost of debt. Therefore, as we have approved the incentive cost tracking mechanism provided in IC 8-1-8.8 which will provide for ongoing recovery of costs from ratepayers during the term of the project in a manner that reduces or eliminates shareholder risk, we find that it is not appropriate or necessary to approve an enhanced return on equity in this Cause.

C. Non-Native Sales / Wholesale Native Load. The OUCC has requested that 90% of the non-native sales net profits associated with the Edwardsport IGCC Project be credited to customers and 10% of such net profits be credited to shareholders, or in the alternative that any sales from the Edwardsport IGCC Project be included in the Company's existing non-native sales sharing mechanism under Rider 70.

We agree with the Company that there is no reason to single out this plant for different treatment; rather any non-native sales associated with this plant should be subject to the existing Commission-approved sharing mechanism under Rider 70. While other methods for the treatment of non-native sales may be appropriate, one of the benefits of the Company's non-native sales profit tracking mechanism is that it is flexible enough to deal with significant changes that occur between base rate cases. Examples of such changes are increases or decreases in generation available to the utility, changes in energy markets and changes in market prices.

The current tracking mechanism has proven to be a benefit to customers since its inception in 2004, providing customers more than 100% of the net profits received by the Company.[17] The Company, too, has benefited through a reduction in the base level of non-native sales profits included in rates when the Company did not achieve its test period level. The record also demonstrates that this plant is expected to dispatch toward the bottom of the economic stack and as such, is expected to be used almost exclusively for native load. We therefore find no reason to treat non-native sales associated with the plant any differently than the Company's other non-native sales.

14. **Petitioner's Request for Confidential Treatment.** Petitioner filed a Motion for Protection of Confidential and Proprietary Information, with Affidavits of Mr. Zupan, Ms. Jenner and Mr. Rose, on October 24, 2006. In its Motion, Petitioner indicated a need for confidential treatment for various pricing and operating characteristic information associated with the IGCC Project and Duke Energy Indiana's IRP presented in this proceeding (*e.g.* project cost estimates, competing cost estimates and commodity price forecasts) and certain forecasts of wholesale power, fuel and emission allowance prices developed by ICF International. The Affidavits of Mr. Zupan, Ms. Jenner and Mr. Rose indicate that such confidential information has actual or potential independent economic value to competitors, the disclosure of the confidential information could provide competitors with an unfair advantage, and Petitioner and ICF have taken all reasonable steps to protect the confidential information from disclosure. In a November 1, 2006, Docket Entry, the Presiding Officers made a preliminarily finding that such information should be subject to confidential treatment.

In addition, Petitioner filed a Motion for Protection of Confidential and Proprietary Information, with Affidavits of Messrs. John B. Lavelle, Dennis Lear and Dennis Zupan, on March 30, 2007. In this Motion, Petitioner indicated a need for confidential treatment for various pricing, technical and operating characteristic information, provided by GE and Bechtel to Petitioner, associated with the IGCC Project, including, in particular, confidential information received by Petitioner in connection with the FEED Study. The Affidavits of Messrs. Lavelle, Lear and Zupan indicate that such confidential information has actual or potential independent economic value to competitors, the disclosure of the confidential information could provide competitors with an unfair advantage, and Petitioner, GE and Bechtel have taken all reasonable steps to protect the confidential information from disclosure. In an April 17, 2007, Docket Entry, the Presiding Officers made a preliminarily finding that such information should be subject to confidential treatment.

Based on the foregoing, pursuant to IC 5-14-3-4(a)(4), we find that the various pricing and operating characteristic information associated with the IGCC Project and Duke Energy Indiana's IRP presented in this proceeding (*e.g.* project cost estimates, competing cost estimates and commodity price forecasts), certain forecasts of wholesale power, fuel and emission allowance prices received from ICF International, as well as various pricing, technical and operating characteristic information provided by GE and Bechtel to Petitioner, associated with the IGCC Project, including, in particular, confidential information received by Petitioner in connection with the FEED Study, are "trade secrets" and should be afforded confidential

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[17] *PSI Energy, Inc.*, Cause No. 42695 (IURC; Sept. 14, 2005); *PSI Energy, Inc.*, Cause No. 42870 (*Ind. Util. Reg. Comm'n*, June 28, 2006); *Duke Energy Indiana, Inc.*, Cause No. 43074 (*Ind. Util. Reg. Comm'n*, June 13, 2007).

treatment. Accordingly, the information is exempted from public disclosure and will be held as confidential by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION, that:

1. Petitioner Duke Energy Indiana, Inc., is hereby issued certificates of public convenience and necessity and clean coal technology for the Edwardsport IGCC Project under IC 8-1-8.5 and 8-1-8.7. This Order constitutes the certificates.

2. The $1.985 billion estimated construction cost for the IGCC Project is hereby approved by the Commission based on the evidence of record.

3. Petitioner is hereby granted certain financial incentives for the IGCC Project pursuant to IC 8-1-8.8. Consistent with the findings set forth in this Order we hereby deny the Petitioner's request for an incremental 150 basis points on the return on shareholder equity that would otherwise be allowed to be earned on the IGCC Project.

4. Petitioner shall be entitled to timely recovery of its construction, operating and maintenance costs incurred in connection with the IGCC Project through its Standard Contract Rider No. 61. Petitioner's proposed Standard Contract Rider No. 61 ("IGCC Rider") is hereby approved to recover the following categories of costs related to the IGCC Project: (1) financing or CWIP costs; (2) O&M costs, including, but not limited to, depreciation, property taxes, increased payroll costs, property insurance; (3) external costs, excluding IRP costs; and (4) transmission costs, excluding any amounts received in the RECB process. Petitioner's proposal for reconciliation of O&M expenses in the IGCC Rider is approved. Petitioner is directed to reduce O&M expense recovery for the IGCC Project by the O&M expenses applicable to the retiring Edwardsport steam generating plant in the amount of $5,756,000 on an annual basis, before jurisdictional allocation, as proposed by Petitioner. Petitioner is directed to file the IGCC Rider with the Commission's Electricity Division, including any changes necessitated by our findings herein.

5. Petitioner shall file IGCC Rider proceedings semi-annually and may initiate its first IGCC Rider proceeding under the Cause No. 43114 IGCC-1 within 60 days following the issuance of this Order. The caption in that proceeding shall accurately reflect the relief requested and subsequent filings shall continue to utilize this Cause No. with the next numeric IGCC filing designation. The Commission shall conduct ongoing review of the construction of the IGCC Project in conjunction with the Petitioner's semi-annual IGCC Rider proceedings.

6. Petitioner shall be permitted to continue the accrual of AFUDC and deferral of operating expenses after the in-service date of the IGCC Project to the extent that costs are not reflected in Duke Energy Indiana's retail electric rates (*i.e.*, through the IGCC Rider or in base rates).

7. Depreciation of the IGCC Project shall be for a period of 30 years. Petitioner shall conduct a depreciation and cost of removal study prior to the IGCC plant going in-service and provide the results of such study, including any amount of negative net salvage value

requested, to the Commission in one of its semi-annual IGCC Rider filings, prior to the commercial operation date of the IGCC Project.

8. Petitioner shall credit retail customers with the reduction of tax expense related to Petitioner's receipt of state, local and federal tax incentives. With respect to the federal investment tax credit, Petitioner shall amortize such tax credit ratably over the thirty-year regulatory life of the IGCC Project and pass the jurisdictional portion of this credit through to retail customers through the IGCC Rider.

9. Petitioner shall exclude deferred taxes from the capital structure used in the IGCC Rider and include the deferred tax balance related to the IGCC Project as an IGCC rate base offset.

10. Petitioner shall recover fuel costs applicable to the IGCC Project through its Standard Contract Rider No. 60 FAC proceedings and emission allowance costs through its Standard Contract Rider No. 63.

11. Petitioner shall include any non-native or off-system sales generated from the IGCC Project in its currently approved non-native sales sharing mechanism, Standard Contract Rider No. 70.

12. As discussed herein and as a condition of this Order, Duke Energy Indiana shall initiate a proceeding with the Commission within six (6) months of the date of this Order regarding further study and potential implementation of partial CO_2 capture at the IGCC Project and further study and potential implementation of CO_2 sequestration and/or enhanced oil recovery.

13. Monthly reports filed with the Lieutenant Governor pursuant to IC 8-1-8.8-13, shall also be filed with the Commission in this Cause.

14. The confidential information presented in this proceeding is found to be confidential and trade secret, excepted from public access, and will continue to be held as confidential by the Commission.

15. This Order shall be effective on and after the date of its approval.

HARDY, GOLC, LANDIS, SERVER AND ZIEGNER CONCUR:
APPROVED: NOV 20 2007

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission